Line of Sight

2016 Annual Report

A clear line of sight

delivered everything

we set out to accomplish

in 2016 and much more.

DEAR FELLOW SHAREHOLDERS,

At Noble Energy we are committed to being the premier upstream oil and natural gas company, delivering superior long-term shareholder return. Not only was 2016 a year of outstanding operational, financial, and safety performance, it was also one of great progress on our strategic objectives. I am confident these results have us positioned to deliver top-tier long-term performance.

In this report, I have outlined 2016 accomplishments and our focus on four strategic cornerstones: onshore U.S. assets, Eastern Mediterranean assets, portfolio, and financial capability. I've also included a discussion about our leadership with all stakeholders.

DRIVING INDUSTRY LEADING DEVELOPMENT AND OPERATION OF TOP-TIER ONSHORE ASSETS

Three years ago we made the strategic decision to increase Noble Energy's onshore U.S. oil exposure and take advantage of our horizontal development experience. This led to our merger with Rosetta Resources Inc. in 2015 and the signing of an agreement to acquire Clayton Williams Energy, Inc. (CWEI) earlier this year. These transactions increase our exposure to high margin liquids production with net unrisked resources of 2 billion barrels of oil equivalent in the Delaware Basin and 460 million barrels of oil equivalent in the Eagle Ford. This fits well with our 2 billion barrels of oil equivalent of net unrisked resources in the DJ Basin.

In 2016, we focused on demonstrating superior drilling and productivity performance across our onshore areas. Approximately two-thirds of our company's 2016 organic capital expenditures went into our Colorado and Texas assets. We are accelerating value realization from this great resource base with the addition of three rigs to our drilling program in late 2016, bringing the total to seven. We expect to further increase our rig count in 2017.

At year end, the DJ Basin remained our largest onshore producing asset, with the majority of our activity in the Wells Ranch and East Pony areas. In these areas, we continued to improve our drilling efficiency and increased recoveries from our production results. An acreage swap in Wells Ranch added more than 11,000 net acres to this position, allowing us to drill additional extended reach lateral wells. A constitutional amendment approved by Colorado voters in November is expected to provide more regulatory stability for responsible oil and natural gas development in the state.

In Texas, we recorded our first full year of activity in the Delaware Basin and Eagle Ford plays acquired in the Rosetta Resources merger. We are delivering some of the industry's best wells in both plays, as we apply learnings from our DJ Basin and Marcellus operations. Activity increased during the fourth quarter with the addition of two drilling rigs in the Delaware Basin and another in the Eagle Ford. Upon the expected closing of the CWEI transaction in the second quarter of 2017, our Delaware Basin lease

LEFT: David L. Stover - Chairman, President and Chief Executive Officer, Noble Energy

ABOVE: Noble Energy Executive Officers (left to right) Kenneth M. Fisher - Executive Vice President and Chief Financial Officer • Gary W. Willingham - Executive Vice President, Operations • David L. Stover - Chairman, President and Chief Executive Officer • A. Lee Robison - Senior Vice President, Human Resources and Administration • John T. Lewis - Senior Vice President, Corporate Development • Arnold J. Johnson - Senior Vice President, General Counsel and Secretary holdings will approach 120,000 net acres, making us the second largest leaseholder in the core of the prolific southern Delaware.

In the Marcellus, we agreed with our partner to dissolve the joint venture to give each company full control over its assets. We retained over 360,000 net acres in West Virginia and Pennsylvania along with a substantial amount of natural gas production. Our near-term focus remains on our inventory of drilled uncompleted wells.

The Noble Midstream Partners (NBLX) initial public offering in the third quarter exceeded its pre-offering target price, generating approximately $300 million in net proceeds, and continues to be a strong market performer. Noble Energy's growing operations in the DJ and Delaware Basins provide strong long-term growth opportunities for NBLX.

We demonstrated superior drilling and productivity performance.

MAXIMIZING THE VALUE OF WORLD CLASS EASTERN MEDITERRANEAN ASSETS

In 2016, our focus was defining the next stages of development for our Eastern Mediterranean assets, ensuring sufficient funding for our expansion plans without impacting investment in other core areas. We continue to be excited about the near and long-term opportunities presented by our Eastern Mediterranean portfolio. Sales volumes from Tamar set new records in 2016. This was enabled by our solid operational performance and Israel's industrial growth, high seasonal residential demand, and accelerated replacement of coal in power generation. Our sale of a 3.5% working interest in Tamar exhibited market strength and high asset value.

The Leviathan project is the next phase of developing our world-class Eastern Mediterranean assets. By 2020, we will have doubled our gross production capacity to over 2 billion cubic feet per day, with visibility to double again over the next decade. This high-margin production is comparable to the best onshore U.S. plays.

The Israeli government's strong support, including the recently enacted natural gas framework, paved the way for the development of Leviathan. We've signed total sales contracts of over $15 billion for Leviathan gas, including domestic and export customers. Leviathan phase one first gas deliveries are targeted for the end of 2019.

MAINTAINING A HIGH QUALITY PORTFOLIO OF INVESTMENT CHOICES

We are benefitting from the range of opportunities provided by our premier portfolio. Beyond the Eastern Mediterranean, our offshore assets maintained their outstanding performance in 2016 and generated steady cash flow support to other business ventures. In the Gulf of Mexico, we brought the Gunflint tie-back project online and continued to see strong production from Big Bend and Dantzler. In Equatorial Guinea, we commenced production at mid-year from the non-operated B3 compression platform in the Alba field.

Our exploration program is focused on high-grading and adding inventory that can provide meaningful future impact to our business. We expect to participate in the drilling of a material prospect offshore Suriname late 2017. We also acquired interests in four new blocks covering close to 700,000 net acres offshore Newfoundland, Canada, each of which holds the potential for at least a billion barrel gross resource.

Maintaining a high-quality portfolio of investment choices means we are always testing whether some portion of our portfolio might be more valuable to someone else. Where appropriate, we look for opportunities to accelerate value for our shareholders by divesting assets that no longer fit our investment plans. In 2016, we realized $1.5 billion of divestiture proceeds to help concentrate our efforts and solidify our balance sheet.

ENSURING ROBUST FINANCIAL CAPABILITY

Throughout the commodity price downturn, we continued to maintain our financial strength and flexibility, including our investment grade credit rating. To address the challenges of this environment, we cut our capital spending by approximately half from the previous year and managed our business within organic cash flow.

We ended the year with $5.2 billion in liquidity, paid down $850 million in debt, and accelerated our onshore program, while pre-funding the expected initial Leviathan spend. Unit lease operating expenses were down nearly 20%, while unit general and administrative expenses were 15% lower year over year. By nearly any measure – volumes, product mix, cost control, cash generation – we did precisely what we said we would do all year, and more.

> *Our growth outlook rivals any of our peers.*

ENVIRONMENTAL, SOCIAL AND GOVERNANCE LEADERSHIP

Some of our greatest accomplishments go beyond our operational and financial results. We recognize that we have many stakeholders, including our shareholders, governments, non-governmental organizations and the communities in which we operate. We strive to be an active member in each of our communities, and are working with them as we live our purpose of *Energizing the World, Bettering People's Lives*. We are proud to tell the stories of our commitment in our annual sustainability report, which we have now published for the last five years.

Safety is always our priority. We are pleased that in 2016 we set a company record low lost time incident rate, and matched the recordable incident rate record we established in 2015. We emphasize safety as a sustainable culture, setting the tone at the top through a dedicated Board of Directors committee.

We continue to enhance our operations to minimize impact on the environment and work with stakeholders to address concerns. In Colorado, for example, we collaborated with government regulators and non-governmental organizations to develop and advance rational, science-based detection and controls for fugitive gas emissions.

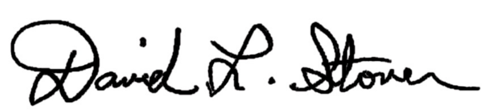
We believe in the principles of strong governance, maintaining awareness of governance trends and shareholder concerns. We have ongoing risk management, compliance and ethics, and shareholder engagement programs. We work continually to improve transparency and clarity in our public disclosures. As one example, 2016 was the third year in which we held a first-place ranking of all S&P 500 companies in the CPA-Zicklin Index of Corporate Political Disclosure and Accountability.

LINE OF SIGHT

In 2016, Noble Energy performed at the highest levels I've seen in my 14 years with the company. We exceeded our original volume forecast by nearly 8% – 30 thousand barrels of oil equivalent per day – driven by outperformance across all our operating areas. This was accomplished with much less capital than originally planned. With our onshore U.S. productivity and cost improvements, the expansion in the Delaware Basin, and our progress on Leviathan, we have generated tremendous momentum.

Our growth outlook rivals any of our peers. I firmly believe our premier portfolio of assets, industry leading execution, and robust financial strength and flexibility will deliver superior long-term shareholder return.

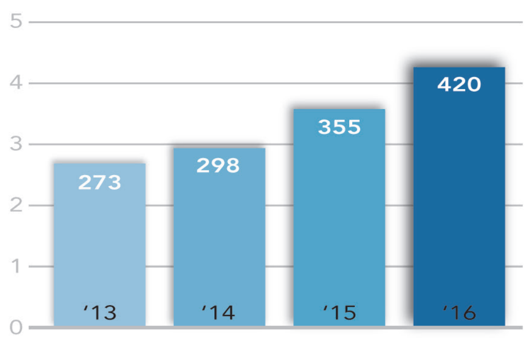
I thank our Board of Directors for their guidance, our employees for their dedication and performance, and our shareholders for their continued trust and confidence.



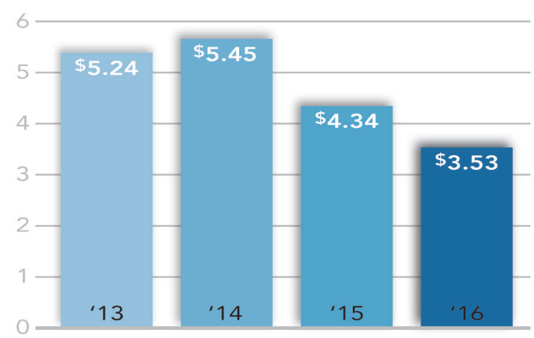
David L. Stover
Chairman, President and CEO

Operational and Financial Outperformance

Sales Volumes[1] (MBoe/d)

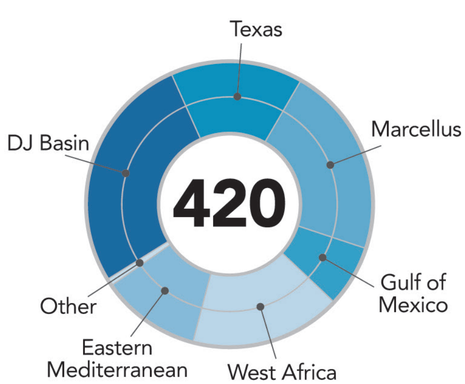


Unit Cost[1] ($/Boe)

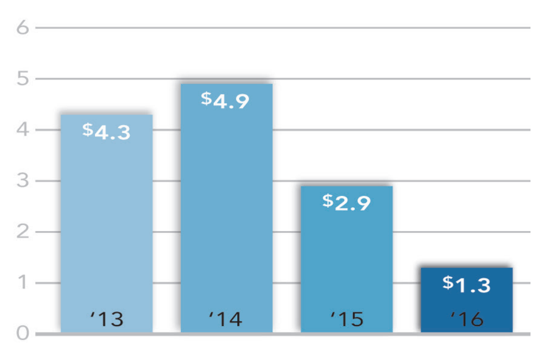


(Unit cost represented is lease operating expenses)

2016 Sales Volumes By Asset[1] (MBoe/d)



Total Capital Expenditures ($Bn)



(Excludes capital lease accruals and corporate acquisitions)

[1] Includes sales from equity method investees

Operational Areas

DJ Basin
Colorado, United States

- Approximately 350,000 net acres in the liquids-rich sector of this premier U.S. oil play
- 2016 production: 114 MBoe/d
- Activity focused in the Wells Ranch and East Pony areas, with about 120,000 acres combined
- Maximizing efficiencies with extended reach laterals and enhanced completion designs
- Noble Midstream Partners provides critical growth infrastructure and added value

Delaware Basin
Permian Basin, Texas, United States

- 40,000 net acres in Reeves County
- 2016 production: 9 MBoe/d
- Strong positions in oil-rich acreage with multiple horizon potential
- Accelerated drilling and completion activity with two rig additions in late 2016
- Noble Midstream Partners increasing value by developing critical gathering infrastructure

Eagle Ford Shale
Texas, United States

- 50,000 net acres, primarily in Dimmit and Webb Counties
- 2016 production: 54 MBoe/d
- Leveraging onshore technical and operational expertise from other plays to materially improve efficiency and productivity
- Applying learnings from Lower Eagle Ford enhanced completions to Upper Eagle Ford

Marcellus Shale
Pennsylvania and West Virginia, United States

- Approximately 360,000 net acres in leading U.S. natural gas play
- 2016 production: 546 MMcfe/d
- Dissolved upstream joint venture in 2016 for maximum control of assets
- Near-term focus on completing drilled but uncompleted wells

Eastern Mediterranean
Offshore Israel and Cyprus

- Approximately 564,000 gross acres offshore of Israel and Cyprus
- 2016 sales volumes: 283 MMcfe/d (all in Israel)
- Discovered gross resources: 35 Tcf
- Signed gas sales contracts with Israel domestic and regional customers
- Drilling additional production well at Tamar, planned drilling at Leviathan in 2017

Gulf of Mexico
Offshore Louisiana, United States

- Approximately 243,000 net acres offshore Louisiana, United States
- Eight producing fields
- 2016 sales volumes: 30 MBoe/d
- Proven track record of exploration and project development success
- Brought Gunflint project online mid-year, continued strong production from Big Bend and Dantzler fields, and assumed operatorship of Thunder Hawk platform

West Africa
Offshore Equatorial Guinea and Cameroon

- Approximately 296,000 net acres offshore Equatorial Guinea and Cameroon
- 2016 sales volumes: 72 MBoe/d (all in Equatorial Guinea)
- Maximizing production from Alba, Alen and Aseng fields
- Commenced production mid-year from B3 compression platform in the Alba field
- Reviewing seismic data for potential future exploration and development opportunities

Acreage positions at Dec. 31, 2016

Financial Outcomes

OPERATING DATA	2016	2015	2014	2013	2012
Year-end Proved Reserves					
Liquids (MMBbls) [1]	**552**	496	432	435	357
Natural Gas (Bcf)	**5,308**	5,549	5,833	5,828	4,964
Total (MMBoe)	**1,437**	1,421	1,404	1,406	1,184
Sales Volumes from Continuing Operations					
Liquids (MBbl/d) [1]	**186**	158	133	123	109
Natural Gas (MMcf/d)	**1,397**	1,187	992	901	774
Total (MBoe/d)[1]	**420**	355	298	273	239
Average Sales Price					
Crude Oil and Condensate (per Bbl) [2]	**$ 40.39**	$ 45.00	$ 91.58	$ 100.29	$ 101.52
Natural Gas (per Mcf)	**$ 2.42**	$ 2.44	$ 3.38	$ 2.97	$ 2.19

FINANCIAL DATA (In millions, except per share amounts and ratios)	2016	2015	2014	2013	2012
Revenues	**$ 3,491**[3]	$ 3,183[3]	$ 5,115[3]	$ 5,015	$ 4,223
Net Income (Loss) Attributable to Noble Energy	**$ (998)**	$ (2,441)	$ 1,214	$ 978	$ 1,027
Net Income (Loss) per Share Diluted [4]	**$ (2.32)**	$ (6.07)	$ 3.27	$ 2.69	$ 2.86
Weighted Average Shares Diluted [4]	**430**	402	367	363	359
Cash Dividends per Share [4]	**$ 0.40**	$ 0.72	$ 0.68	$ 0.55	$ 0.45
Net Cash Provided by Operating Activities	**$ 1,351**	$ 2,062	$ 3,506	$ 2,937	$ 2,933
Capital Expenditures [5]	**$ 1,339**	$ 2,852	$ 4,883	$ 4,311	$ 3,626
Total Assets	**$ 21,011**	$ 24,196	$ 22,553	$ 19,642	$ 17,554
Total Debt	**$ 7,114**	$ 7,976	$ 6,197	$ 4,843	$ 4,123
Shareholders' Equity	**$ 9,600**	$ 10,370	$ 10,325	$ 9,184	$ 8,258
Total Debt-to-Book-Capital Ratio	**43%**	43%	38%	35%	33%

[1] Includes sales from equity method investees

[2] Excludes equity method investees

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

[4] Amounts adjusted for the 2-for-1 stock split which occurred in 2013

[5] Excludes capital lease accruals and corporate acquisitions

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, 2016
or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-07964

NOBLE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	**73-0785597**
(State 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 or a smaller reporting company. See definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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, 2016: $15.4 billion.

Number of shares of Common Stock outstanding as of December 31, 2016: 430,524,340.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2017 Annual Meeting of Stockholders to be held on April 25, 2017, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2016, are incorporated by reference into Part III.

TABLE OF CONTENTS

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, development, and acquisition activities;
- our ability to make and integrate acquisitions;
- 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; 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 a leading independent crude oil and natural gas exploration and production company with a diversified high-quality portfolio spanning three continents and consisting of both US unconventional and global offshore conventional assets. 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 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 conventional basins. We endeavor to maintain a high-quality, growth-oriented portfolio of assets that are well-positioned on the global industry cost supply curve. In addition, our asset portfolio offers operational and investment flexibility.

In US unconventional basins, we have demonstrated competence in applying geological capabilities, drilling and completion expertise and midstream synergies to deliver incremental value. In onshore US, we typically apply a major project development concept to a US unconventional basin by utilizing an Integrated Development Plan (IDP) approach. In the global offshore, we have had notable exploration successes over the past decade, which have led to our entry into new conventional offshore basins, and have executed several major offshore development projects both on schedule and within budget which have provided long-lived cash flows to our business.

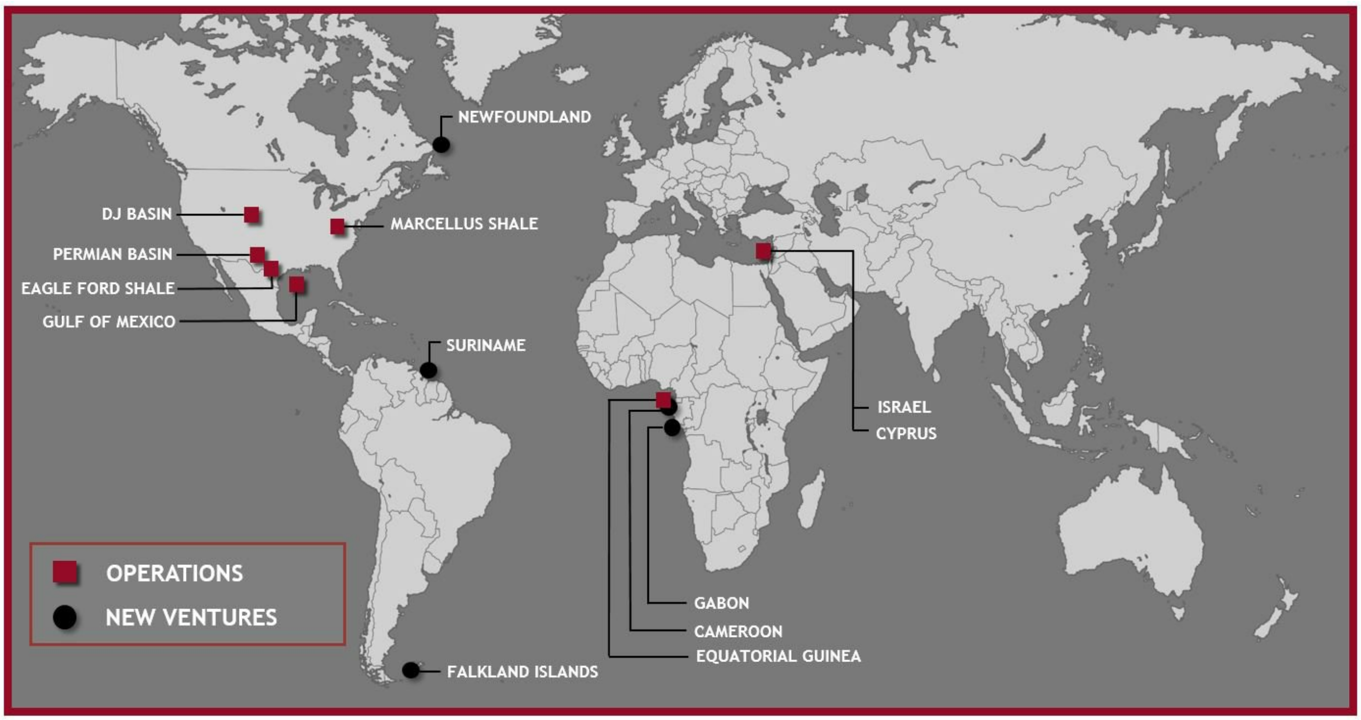
Approximately 75% of our 2017 capital program is allocated to US onshore development, primarily focused on liquids-rich opportunities in the DJ Basin, Delaware Basin and Eagle Ford Shale. Eastern Mediterranean capital expenditures, including initial development costs associated with the Leviathan project, represent over 20% of the total. As we manage our asset portfolio, we will consider expanding the portfolio to include additional long-term and/or large-scale exploration opportunities.

In addition, the majority of our assets are held by production, which provides 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-diversified, growing portfolio delivering attractive financial returns.

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 numerous areas of interest. Our activities include geophysical and geological evaluation; analysis of commercial, regulatory and political risks; and exploratory drilling, 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 midstream assets primarily used in the processing and transportation of our onshore US production.

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



Operating Segments We manage our operations by region. Our segments, each of which is primarily in the business of crude oil, natural gas and NGL exploration, development, production and acquisition, include:

- United States, including the onshore DJ Basin, Permian Basin, Eagle Ford Shale, Marcellus Shale, and offshore deepwater Gulf of Mexico, as well as the consolidated accounts of Noble Midstream Partners LP (Noble Midstream Partners), which completed its initial public offering of common units in 2016;
- Eastern Mediterranean, including offshore Israel and Cyprus;
- West Africa, including offshore Equatorial Guinea, Cameroon, and Gabon; and
- Other International and Corporate, including new ventures such as offshore the Falkland Islands, Suriname, and Newfoundland.

Development Activities Our development projects have resulted from both exploration success as well as periodic strategic acquisitions. These projects provide multiple opportunities for consistent 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 offer sustained cash flows and attractive financial returns, while generally increasing net asset value over the oil and gas business cycle.

Onshore US, our low production-risk development programs, typically centered around IDPs, provide a stable base of production. These programs, which have delivered significant historical production growth, 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 the Tamar natural gas development, offshore Israel, which is currently undergoing expansion. We are also progressing a final investment decision for 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.

Exploration Activities We primarily focus on organic growth from exploration and development drilling activities, concentrating on basins or plays where we have strategic competitive advantages. 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 deepwater 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 over the past decade.

In 2016, we performed limited exploration activities due to the commodity price environment. Also, after review of additional 3D seismic data, modeling and economic assessment, we determined that certain discoveries offshore West Africa were impaired in the current forward outlook for crude oil prices and wrote off related capitalized costs of $468 million, which is included in exploration expense. See International – West Africa (Equatorial Guinea, Cameroon and Gabon) discussion, below.

For 2017, we anticipate engaging in seismic acquisition and processing and potentially drilling an exploratory well offshore Suriname.

Acquisition and Divestiture Activities We maintain an ongoing portfolio management program. Accordingly, we may 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. We may also periodically divest assets through asset or equity sales, exchanges, dissolutions of joint ventures or other transactions.

During 2016, we generated cash of approximately $1.5 billion through asset sales and the initial public offering of Noble Midstream Partners common units.

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 3. Acquisitions, Divestitures and Merger.

Pending Acquisition of Clayton Williams Energy, Inc. On January 13, 2017, we executed a definitive agreement to acquire all of the outstanding common stock of Clayton Williams Energy, Inc. (Clayton Williams Energy) for $2.7 billion in Noble Energy stock and cash. The acquisition includes 71,000 highly contiguous net acres in the core of the Southern Delaware Basin in Reeves and Ward counties in Texas (directly adjacent to our existing 47,200 net acres). In addition, there are an additional 100,000 net acres in other areas of the Permian Basin. The acquisition provides for increased opportunities to drill longer lateral wells on our combined acreage positions, enhances our crude oil production base and future crude oil growth potential, adds to our midstream assets and provides future midstream buildout opportunities.

The transaction has been unanimously approved by the Boards of Directors of both Noble Energy and Clayton Williams Energy and is subject to approval by stockholders of Clayton Williams Energy. If approved, Clayton Williams Energy stockholders will receive 2.7874 shares of Noble Energy common stock and $34.75 in cash for each share of common stock held. In the aggregate, this totals 55 million shares of Noble Energy stock and $665 million in cash. The enterprise value of the transaction, based on Noble Energy's closing stock price as of January 13, 2017, is approximately $3.2 billion in the aggregate including the assumption of approximately $500 million in net debt. We intend to fund the cash portion of the acquisition through a draw on our revolving credit facility.

Closing is expected to occur second quarter 2017 and is subject to customary regulatory approvals, approval by the holders of a majority of Clayton Williams Energy common stock, and certain other conditions.

Proved Oil and Gas Reserves Proved reserves at December 31, 2016 were as follows:

	December 31, 2016			
	Proved Reserves			
Reserves Category	Crude Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe) [1]
Proved Developed				
United States	138	1,817	113	554
Israel	3	1,600	—	270
Equatorial Guinea	34	486	12	127
Total Proved Developed Reserves	175	3,903	125	951
Proved Undeveloped				
United States	158	1,021	94	422
Israel	—	384	—	64
Total Proved Undeveloped Reserves	158	1,405	94	486
Total Proved Reserves	333	5,308	219	1,437

(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 1,437 MMBoe as of December 31, 2016 as compared with 1,421 MMBoe as of December 31, 2015. Changes primarily included the following:

- positive revisions of 117 MMBoe related to our onshore US horizontal drilling programs and Alba field, offshore Equatorial Guinea, driven by increased well performance and/or lower operating or development costs in onshore US and the startup of the Alba B3 compression platform; and
- extensions and other additions of 179 MMBoe related to our onshore US horizontal drilling programs due to successful expansion of our extended reach lateral well programs;

offset by:

- production volumes of 154 MMBoe;
- negative revisions of 53 MMBoe that were commodity price driven; and
- reduction of 77 MMBoe primarily due to our 3.5% reduction in ownership in Tamar, the impact of the Marcellus Shale acreage exchange, and other smaller onshore US divestitures.

Our proved reserves are 68% US and 32% international, and the mix is 38% global liquids (crude oil and NGLs), 29% international natural gas and 33% 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.

United States

We have been engaged in crude oil, natural gas and NGL exploration and development activities throughout onshore US since 1932 and in the Gulf of Mexico since 1968. US operations accounted for 73% of 2016 total consolidated sales volumes and 68% of total proved reserves at December 31, 2016. Approximately 48% of the proved reserves in the US are natural gas, 30% are crude oil and condensate and 22% are NGLs.

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

	Year Ended December 31, 2016				December 31, 2016			
	Sales Volumes				Proved Reserves			
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil & Condensate	Natural Gas	NGLs	Total
	(MBbl/d)	(MMcf/d)	(MBbl/d)	(MBoe/d)	(MMBbls)	(Bcf)	(MMBbls)	(MMBoe)
DJ Basin	56	225	21	114	177	981	80	421
Eagle Ford Shale	10	129	22	54	30	453	76	181
Permian Basin	6	9	2	9	56	75	13	82
Marcellus Shale	1	486	8	91	5	1,275	36	253
Deepwater Gulf of Mexico	25	20	1	30	24	30	2	31
Other Onshore US	1	12	—	3	4	24	—	8
Total	99	881	54	301	296	2,838	207	976

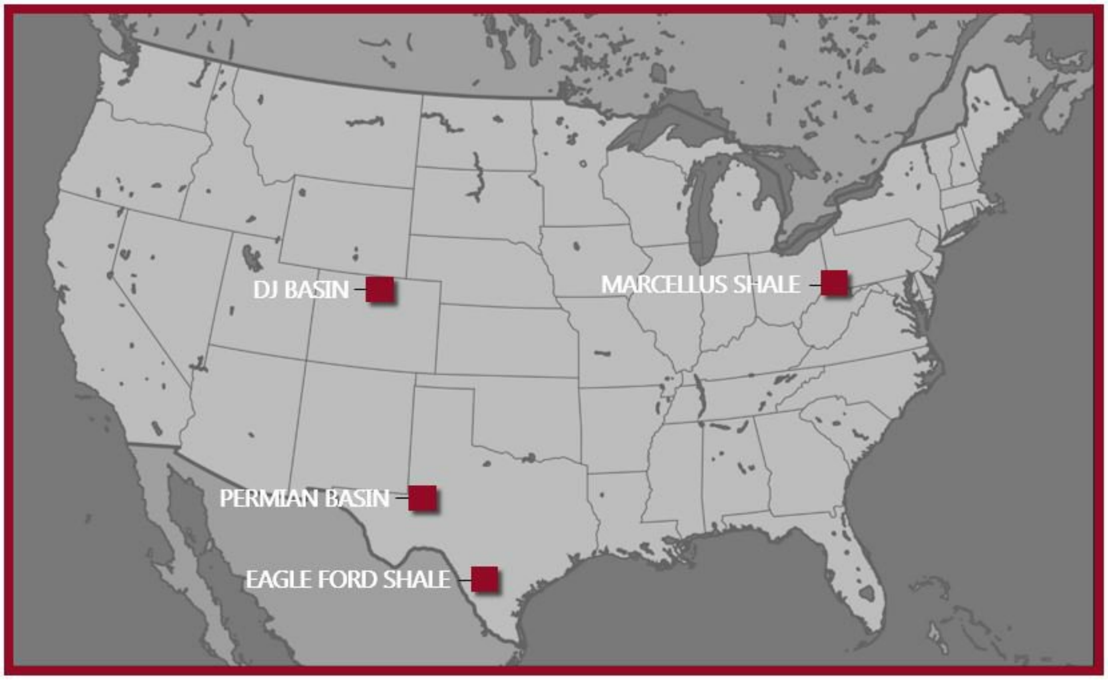
Wells drilled in 2016 and productive wells at December 31, 2016 for our US operating areas were as follows:

	Year Ended December 31, 2016	December 31, 2016
	Gross Wells Drilled or Participated in [(1)]	Gross Productive Wells
DJ Basin	134	6,961
Eagle Ford Shale	22	318
Permian Basin	19	242
Marcellus Shale	17	238
Deepwater Gulf of Mexico	2	15
Other Onshore US	—	21
Total	194	7,795

(1) Excludes exploratory wells drilled and suspended awaiting a sanctioned development plan or being assessed for economic viability. See Drilling Activity, below.

US Onshore

Our onshore US operations are located in proven basins with long-life production profiles and are typically developed utilizing an IDP, such as in the DJ Basin and now in the Permian Basin. These assets provide low production-risk drilling opportunities that offer predictable and long-term production, and a balanced commodity mix of crude oil, natural gas and NGLs. Locations of our onshore US operations as of December 31, 2016 are shown on the map below:



DJ Basin With the advent of horizontal drilling technology, the DJ Basin is recognized as a premier US crude oil resource play and is a key driver of our business and future growth. Our position in the area covers approximately 350,000 net acres.

In 2016 and currently, we are focusing our drilling and development activity on IDP areas, such as Wells Ranch and East Pony, allowing us to consolidate processing and handling infrastructure across large areas (typically 30,000 to 80,000 acres). IDP's are areas of highly contiguous acreage where we can accelerate drilling and completion activities and drill a much higher percentage of extended reach lateral wells. Additionally, our IDP approach has provided an opportunity to efficiently and economically support production growth by constructing and expanding our infrastructure, including constructing our own centralized production facilities, gathering systems, and water infrastructure, across the DJ Basin.

2016 Activity In response to the current commodity price environment, we adopted a reduced but flexible 2016 capital program, and drilling efficiencies gained through longer laterals allowed us to continue an active drilling program in the basin. Operationally, we focused on reducing per unit operating costs while increasing operating efficiencies to support project returns and margin improvements. Through material efficiency gains in drilling, midstream expansions and synergies, and enhanced completion techniques, we were able to deliver 2016 production at lower capital and per unit operating costs than 2015.

Through strategic acreage transactions, we expanded our extended reach lateral well program to approximately 50% of wells drilled in 2016. During the year, we spud 106 horizontal wells, of which 55 were extended reach lateral wells, and 124 wells initiated production. We also participated in approximately 28 non-operated development wells during 2016.

Through continued active management of our portfolio, we facilitated certain asset monetizations which allow for the acceleration of asset development. In 2016, we:

- closed an acreage exchange agreement to receive approximately 11,700 net acres within our Wells Ranch development area in exchange for approximately 13,500 net acres primarily from our Bronco development area, located southwest of Wells Ranch. The exchange enhances our ability to develop the field by improving our contiguous acreage position, increasing our lateral length potential and optimizing our access to central gathering facilities;
- entered into an agreement to divest approximately 33,100 producing and undeveloped net acres in the Greeley Crescent area of Weld County, Colorado for $505 million, representing approximately 8% of our total DJ Basin acreage. We received proceeds of $486 million in 2016 and expect to receive the remaining proceeds in mid-2017. Proceeds received were applied to the field's basis with no recognition of gain or loss. As part of the transaction, all of the acreage in the Greeley Crescent IDP remains subject to dedications to Noble Midstream Partners for crude oil gathering, produced water services and fresh water services; and

- sold certain other producing and non-producing assets, generating net proceeds of $20 million, which were applied to the field basis, with no recognition of gain or loss.

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

The DJ Basin contributed an average of 114 MBoe/d of sales volumes in 2016, representing approximately 28% of total consolidated sales volumes. DJ Basin sales volumes were approximately 49% crude oil and 18% NGLs. At December 31, 2016, proved reserves in the DJ Basin represented approximately 29% of our total proved reserves. See Proved Reserves Disclosures, below.

We exited 2016 with a two rig drilling program and intend to increase to three rigs in the second quarter of 2017. We remain engaged in a comprehensive effort to focus on capital and cost efficiencies and have adopted a capital spending program for 2017 that is supported by operating cash flows. Our spending program further provides flexibility to reassess activity levels in response to the commodity price environment as it evolves during the remainder of 2017.

Midstream Activity 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 onshore US midstream investment program. Noble Midstream Partners owns, operates and will develop certain of our DJ Basin crude oil, natural gas and water-related midstream infrastructure and will also develop crude oil and produced water midstream infrastructure in our Delaware Basin position of the Permian Basin.

Permian Basin Our Permian Basin and Eagle Ford assets were added to our portfolio through the merger with Rosetta Resources Inc., on July 20, 2015 (Rosetta Merger), which increased our development inventory and further diversified our portfolio. Our operations in the Permian Basin are focused in Reeves County in the Southern Delaware Basin and as of December 31, 2016, we held approximately 40,000 net acres in the Delaware Basin and approximately 10,000 net acres in the Midland Basin.

Encouraged by our 2016 well results, we executed strategic leasing initiatives and entered into a bolt-on acquisition, for $295 million, which closed in early 2017. The acquisition included seven producing wells, of which four will be operated by us. The combined transactions added approximately 7,200 net acres with 2,400 Boe/d, net, of production near our producing properties and increased our contiguous acreage position in the Reeves County area.

Including our recently-announced acquisition of Clayton Williams Energy, which is expected to close in second quarter 2017, our Southern Delaware Basin acreage position will increase to approximately 120,000 net acres. See Pending Acquisition of Clayton Williams Energy, Inc., above.

2016 Activity We have tested multiple drilling and completion techniques utilizing slickwater, high intensity completions, increased proppant concentrations and longer laterals, which have led to stronger well performance and capital efficiencies.

In 2016, we operated one to three drilling rigs, drilled nine horizontal wells and commenced production on nine operated wells. In addition, we engaged in the construction of certain midstream assets, including our first central gathering facility, which we expect will be online in 2017.

For 2016, our assets in the Permian Basin contributed an average of 9 MBoe/d of sales volumes, representing approximately 2% of total consolidated sales volumes, and were approximately 67% crude oil and 17% NGLs. These assets represented approximately 6% of total proved reserves at December 31, 2016.

For 2017, we started the year with three rigs operating on our current acreage in the Permian Basin, and Clayton Williams Energy started the year with one rig operating on its acreage. We plan to add a second rig to the new acreage in second quarter 2017, following closing of the Clayton Williams Energy acquisition, and a third rig later in the year, in order to exit 2017 with a combined six rigs running in the Delaware Basin. While our 2017 capital program will focus on long laterals, pad drilling and multi-zone testing for our Permian Basin assets, it provides for flexibility and can be modified in response to changes in the commodity price environment.

Eagle Ford Shale Since our entry into the Eagle Ford Shale, we have applied IDP learnings from other onshore US assets to realize cost efficiencies, enhance completion designs and optimize well placement, thereby positively impacting costs and performance associated with our Texas assets.

We hold approximately 35,000 net acres located in the liquids-rich area of the play, including producing assets in Webb and Dimmit counties. Since acquiring these assets, we have worked to optimize drilling and completion designs to further develop both the Upper and Lower Eagle Ford zones, including the utilization of slickwater as a completion fluid and testing varying cluster spacing, lateral lengths and proppant quantities.

2016 Activity Our 2016 capital program was primarily focused within Webb and Dimmit counties where we operated one to two drilling rigs, drilled 22 horizontal wells and commenced production on 27 operated wells. We also closed the divestiture of certain assets located in La Salle, Atascosa, Live Oak and Dimmit counties where we had not engaged in drilling activities since the Rosetta Merger. Proceeds received totaled $68 million and were applied to the field's basis with no recognition of gain or loss.

For 2016, our assets in the Eagle Ford Shale contributed an average of 54 MBoe/d of sales volumes, representing approximately 13% of total consolidated sales volumes, and were approximately 19% crude oil and 41% NGLs. These assets represented approximately 13% of total proved reserves at December 31, 2016.

We exited 2016 with a two rig drilling program and in 2017, we will continue to evaluate results from our development program. Our capital program in 2017 provides flexibility to prudently manage our resources in response to changes in the commodity price environment.

Marcellus Shale The Marcellus Shale contains a significant quantity of natural gas resources, and its proximity to high-demand East Coast markets has made it a desirable area for development. Infrastructure improvements and expanding firm transportation capacity are expected to improve export of product to areas outside the basin, reduce basis differentials, and have a positive impact on project economics.

In an effort to allow flexibility and enhance control over the pace and scale of development of our Marcellus Shale investment, we and our joint venture partner, CONSOL Energy Inc. (CONSOL), agreed to terminate our 50-50 Joint Development Agreement (JDA) on October 29, 2016 with an effective date of October 1, 2016. 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. As a result, we now hold an almost 100% interest in approximately 363,000 acres, primarily located in the wet gas area of northwest West Virginia and a small acreage position in southwest Pennsylvania, with associated sales volumes of approximately 450 MMcfe/d. We anticipate a decline in sales volumes of approximately 100 MMcfe/d in 2017 and our proved reserves as of December 31, 2016 reflect divestment of approximately 185 Bcf (or 25 MMBoe, net of 4 MMBls of NGL reserves acquired) in the Marcellus Shale driven by our asset exchange. 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 contingent carry cost obligation of $1.6 billion due from us.

2016 Activity Prior to the termination of the JDA, the joint venture completed 17 wells and initiated production on 42 wells. During the year, we focused on well completions, while not performing any drilling activities in response to low commodity prices. However, operational performance remained strong, with volumes increasing 18% compared to 2015 and we achieved material reductions in operating expense as compared with the prior year.

Our allocated capital investment in the Marcellus Shale was limited to the completion of previously-drilled wells in our non-operating dry gas areas. After the termination of the JDA, we focused on the completion of two wells in our wet gas areas.

The Marcellus Shale contributed an average of 546 MMcfe/d of sales volumes, approximately 22% of total consolidated sales volumes in 2016, and represented approximately 18% of total proved reserves at December 31, 2016. See also Proved Reserves Disclosures, below.

Our 2017 capital program is flexible and includes the completion of previously drilled wells. We currently have no rigs running in the Marcellus Shale but have the potential to add one rig at year-end 2017.

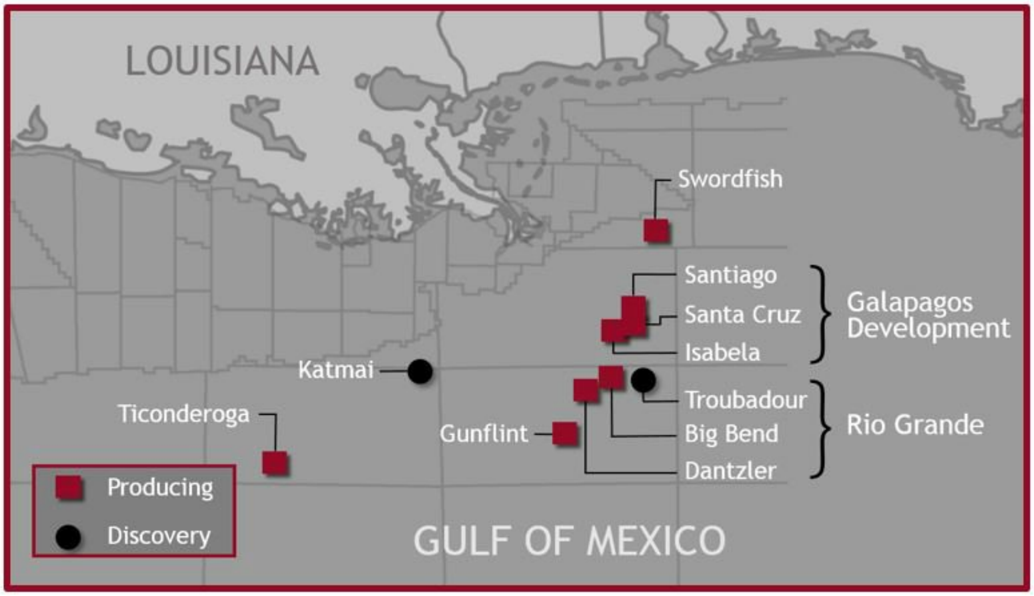
CONE Gathering We and CONSOL each own a 50% interest, and have joint control of CONE Gathering LLC (CONE Gathering), which constructs, owns and operates midstream infrastructure servicing our production in the Marcellus Shale. CONE Gathering owns the general partner controlling interest in CONE Midstream Partners LP (CONE Midstream), a master limited partnership, formed in late 2014. Through our 50% ownership interest in the general partner of CONE Midstream, we have significant influence over the management and operations of CONE Gathering and CONE Midstream in accordance with overall strategic plans, including the maintenance and development of our Marcellus Shale assets and monetization of natural gas production within the basin.

During 2016, CONE Midstream continued to increase both revenues and average throughput as a result of new well connections and the impact of de-bottlenecking projects coming online.

In fourth quarter 2016, CONE Midstream completed an acquisition of assets from CONE Gathering, which increased our ownership of CONE Midstream common units from 32.1% to 33.5%. CONE Gathering distributed cash of $70 million to us. See Item 8. Financial Statements and Supplementary Data – Note 7. Equity Method Investments.

Bowdoin Sale During 2016, we completed the sale of our Bowdoin property (north central Montana), generating proceeds of $43 million, and recognizing a $23 million loss.

Deepwater Gulf of Mexico Locations of our operations in the deepwater Gulf of Mexico as of December 31, 2016 are shown on the map below:



Our deepwater Gulf of Mexico operations resulted from lease acquisition, expansion of our 3D seismic database, and an oil-levered drilling program. 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 70 deepwater Gulf of Mexico blocks, representing approximately 51,000 net developed acres and approximately 192,000 net undeveloped acres. We are the operator on nearly 80% of our leases. See also *Developed and Undeveloped Acreage – Future Acreage Expirations*, below.

2016 Activity Our activity in 2016 primarily focused on commencing production from our Gunflint crude oil discovery, drilling our exploratory Silvergate prospect and the Katmai 2 appraisal well and performing certain remediation activities. We also successfully completed the planned decommissioning of the Raton field and the plug and abandonment work for Lorien. See Offshore Producing Properties and Update to Major Gulf of Mexico Projects, below.

The deepwater Gulf of Mexico contributed an average of 30 MBoe/d of sales volumes in 2016, approximately 7% of total consolidated sales volumes, and represented approximately 2% of total proved reserves at December 31, 2016.

Our 2016 capital program included the use of the Atwood Advantage drillship, which is under a multi-year contract for services and has been redeployed to offshore Israel. See [Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Contractual Obligations](#). Our 2017 exploration budget has been reduced, but provides flexibility to respond to commodity price changes.

During 2016, we completed our geological evaluation of certain deepwater Gulf of Mexico leases and determined that several leases, representing $91 million of undeveloped leasehold cost, should be impaired and written off. As a result, we recognized $58 million of undeveloped leasehold impairment expense and recorded a $33 million decrease in our valuation pool of individually insignificant leases.

We have remaining capitalized undeveloped leasehold cost of approximately $105 million related to deepwater Gulf of Mexico prospects that have not yet been drilled. Leases representing over 75% 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, future undeveloped leasehold amortization and impairment expense could be significant.

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 contributed 4 MBoe/d of sales volumes in 2016.

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 16 MBoe/d of sales volumes in 2016.

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. During 2016, workover activities were conducted at Isabela to remediate the well, production commenced in the second half of 2016, and well stimulation was performed in fourth quarter 2016 to enhance recovery. Galapagos contributed an average of 5 MBoe/d of sales volumes in 2016.

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 floating offshore production platform.

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. These properties are connected to existing infrastructure through subsea tiebacks.

Update to Major Gulf of Mexico Projects

Silvergate (Mississippi Canyon Block 339; 50% operated working interest) Drilling operations were completed at our Silvergate exploration well. The well did not encounter commercial quantities of hydrocarbons and has been plugged and abandoned. In 2016, we recorded dry hole expense of $87 million associated with this well.

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 second quarter 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 of December 31, 2016, we have capitalized approximately $43 million of costs associated with our Katmai 2 appraisal well.

Troubadour (Mississippi Canyon Block 699; 60% operated working interest) Troubadour is a 2013 natural gas discovery for which we are currently evaluating development scenarios, including subsea tieback to existing infrastructure.

Asset Impairments We recorded property impairment expense of $158 million in 2015. See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

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, Item 1A. Risk Factors, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Oil and Gas Exploration Expense.

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 contributed substantially to our growth over the last decade.

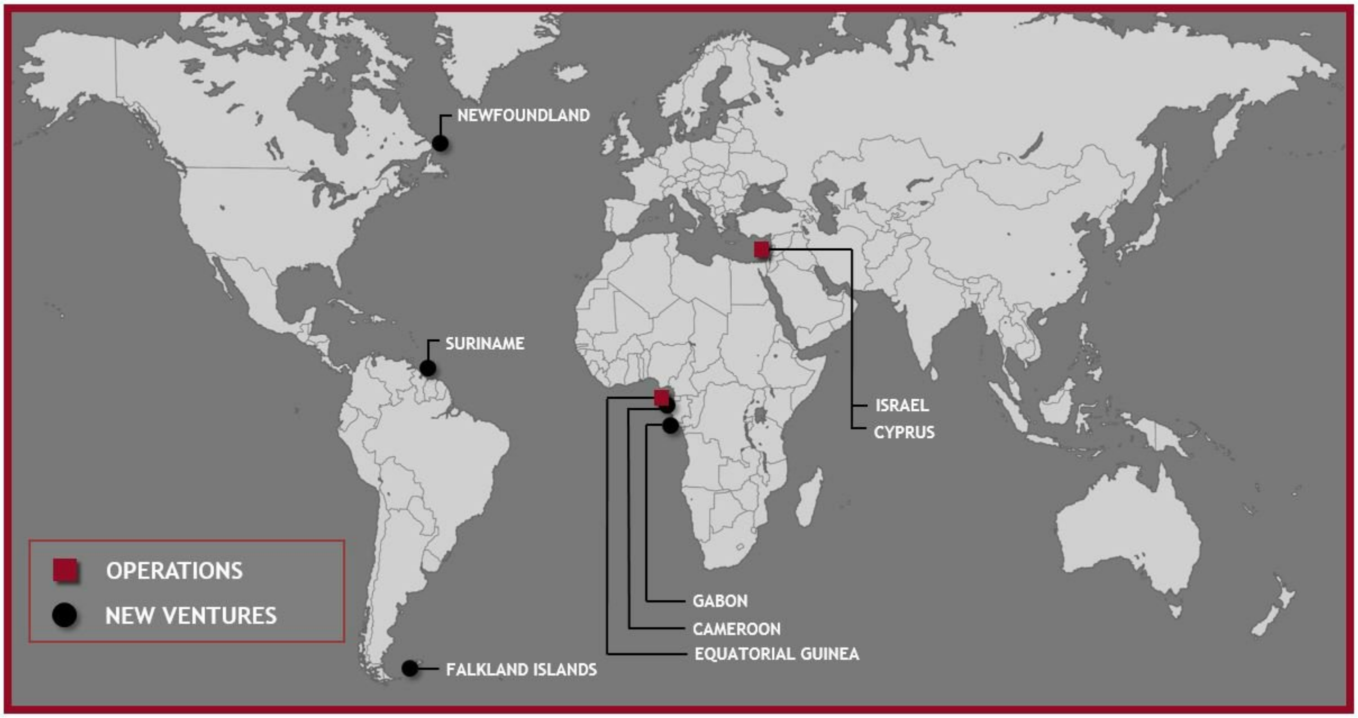
Previous exploration successes offshore Israel, West Africa, and Cyprus have identified multiple major development projects that have the potential to contribute to production growth in the future.

On the development side, during 2016, we began drilling the Tamar 8 development well and advanced Eastern Mediterranean regional natural gas export opportunities. Offshore Equatorial Guinea, the operator of the Alba field completed the Alba field compression project, resulting in extension of field life and improved field economics. We also wrote off capitalized exploratory costs related to certain discoveries offshore West Africa. See Eastern Mediterranean (Israel and Cyprus) and West Africa (Equatorial Guinea, Cameroon and Gabon), below.

International operations accounted for 27% of total consolidated sales volumes in 2016 and 32% of total proved reserves at December 31, 2016. International proved reserves are approximately 89% natural gas and 11% crude oil, NGLs and condensate.

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

Locations of our international operations as of December 31, 2016 are shown on the map below:



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

	Year Ended December 31, 2016				December 31, 2016			
	Sales Volumes				Proved Reserves			
	Crude Oil & Condensate	Natural Gas	NGLs	Total	Crude Oil & Condensate	Natural Gas	NGLs	Total
	(MBbl/d)	(MMcf/d)	(MBbl/d)	(MBoe/d)	(MMBbls)	(Bcf)	(MMBbls)	(MMBoe)
International								
Israel	—	281	—	47	3	1,984	—	334
Equatorial Guinea	26	235	—	65	34	486	12	127
Total International	26	516	—	112	37	2,470	12	461
Equity Investee	2	—	5	7	—	—	—	—
Total	28	516	5	119	37	2,470	12	461
Equity Investee Share of Methanol Sales (MMgal)				162				

Wells drilled in 2016 and productive wells at December 31, 2016 in our international operating areas were as follows:

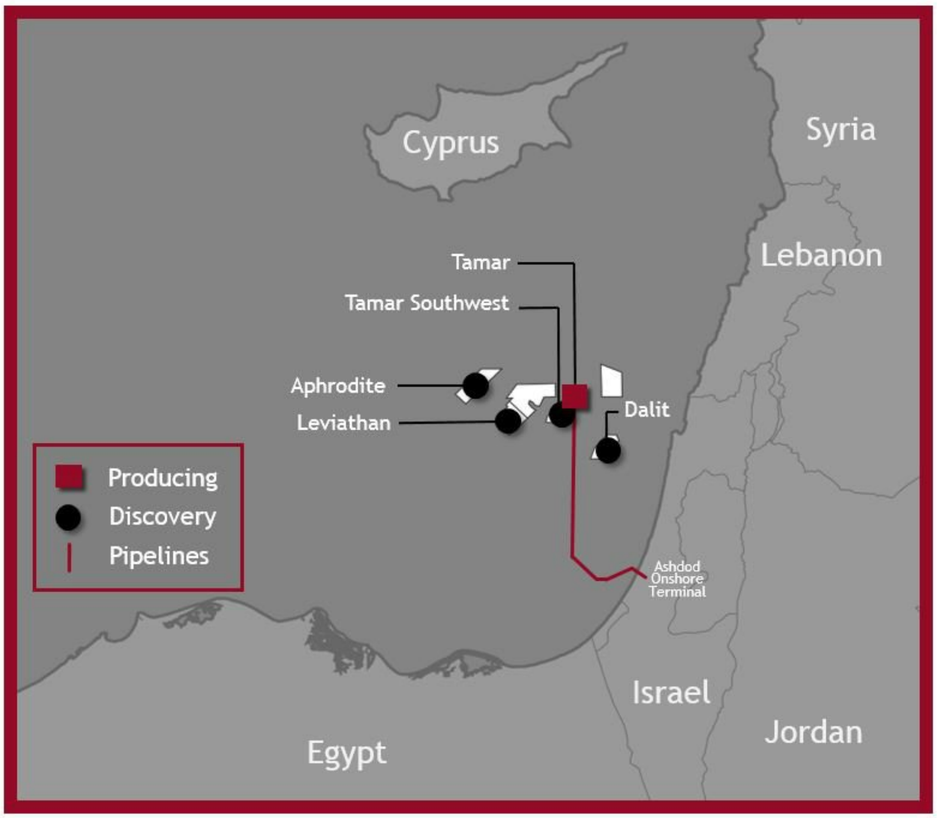
	Year Ended December 31, 2016	December 31, 2016
	Gross Wells Drilled or Participated in	Gross Productive Wells
International		
Israel	—	8
Equatorial Guinea	—	26
Total International	—	34

Eastern Mediterranean (Israel and Cyprus) One of our operating areas is the Eastern Mediterranean, where we have drilled 12 successful exploration and appraisal wells and 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 281 MMcf/d of natural gas sales volumes in 2016, approximately 11% of total consolidated sales volumes, and represented approximately 23% of total proved reserves at December 31, 2016. Our leasehold position in the Eastern Mediterranean at December 31, 2016, included four leases and three licenses operated offshore Israel and one license operated offshore Cyprus.

At December 31, 2016, 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, 2016 are shown below:



Offshore Israel Noble Energy and our partners have delivered reliable and cost effective natural gas to Israeli citizens for over a decade. During this time, we have reliably and consistently delivered approximately 1.9 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.

We continue to partner with customers and the Government of Israel to provide a reliable fuel source to support affordable energy for the people of Israel. 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 power generation.

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 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 has also driven incremental demand for natural gas beginning in 2016. We have executed numerous natural gas sales and purchase agreements (GSPAs) with domestic customers. See International Marketing Activities and Delivery Commitments, below.

Regional Demand and Exports The Eastern Mediterranean presents an opportunity to match our low cost, 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 Leviathan Plan of Development approved by the Government of Israel and nearing final investment decision, we are well positioned to supply natural gas to the region for many years.

Israel Natural Gas Projects

Tamar (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). Growth in power, industrial and residential demand in Israel, coupled with almost 100% uptime, enabled us to set new records for sales from our Tamar field, both on a quarterly basis of 313 MMcfe/d, net, during third quarter 2016 and on a cumulative gross production milestone of one trillion cubic feet from our Tamar field since initial production in first quarter 2013. Net production from Tamar averaged 281 MMcfe/d for 2016. In late October 2016, we spud the Tamar 8 development well which will increase supply reliability as demand for natural gas increases domestically.

The Israel Natural Gas Framework (Framework) provides for reduction in our ownership interest in Tamar to 25% by year-end 2021. In mid-2016, we signed a definitive agreement to divest a portion of our interest in the Tamar field, and in December 2016, we closed the divestiture of 3.5% ownership interest, partially fulfilling this commitment required by the Framework. The total sales price was $431 million. After consideration of timing and tax adjustments, we received cash proceeds of $316 million at closing. Proceeds received were ratably allocated to the field's basis and resulted in the recognition of a $261 million gain. Our proved reserves as of December 31, 2016 reflect a reduction of 214 Bcf of natural gas driven by the divestiture.

Tamar Southwest (32.5% operated working interest) We continue to work with the Government of Israel to obtain regulatory approval of the development plan for our 2013 Tamar Southwest discovery, which is intended to utilize current Tamar infrastructure. Timely development of Tamar Southwest would help reinforce the reliability for our Tamar project and support increased customer demand.

Tamar Expansion Project (32.5% operated working interest) We have also engaged in the planning phase for the Tamar expansion project. The project would expand field deliverability to approximately 2.1 Bcf/d, a quantity that would allow for regional export. Expansion would include a third flow line component and additional producing wells.

Leviathan Natural Gas Project (39.66% operated working interest) The development of Leviathan will substantially expand our capacity to deliver natural gas to Israel and the region, as well as provide a second source of domestic natural gas supply and redundancy of infrastructure. Due to Leviathan's size, full field development is expected to require several development phases. Our Plan of Development was approved by the Government of Israel during mid-2016 and we and our partners are performing front-end engineering design (FEED) studies necessary to progress the project to final investment decision (project sanction) in early 2017 and are targeting production by the end of 2019.

The initial Leviathan field development will be a subsea tie-back to a shallow-water platform with a connection to the Israel Natural Gas Lines (INGL) pipeline network. In fourth quarter 2016, we wrote off $88 million of capitalized concept selection costs associated with certain abandoned development concepts that are no longer viable. See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

Timing of Leviathan project sanction depends on numerous factors, including completion of necessary marketing activities, engineering and construction planning and availability of funds from us and our partners to invest in the project. We have made significant progress on these fronts and are nearing project sanction.

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 executed multiple GSPAs for a total of up to approximately 525 MMcf/d, gross, or approximately 180 MMcf/d, net to Noble Energy, 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. The execution of this agreement is subject to regulatory approvals from both Israel and Jordan. Sales to NEPCO are anticipated to commence at field startup. See Israel Natural Gas Framework and Regulatory Environment, below.

Karish and Tanin The Framework also provided for the divestiture of the Karish and Tanin discoveries, and, in November 2015, we executed an agreement to divest our 47% interest in the Alon A and Alon C offshore Israel licenses, which include the Karish and Tanin fields. The transaction closed in early 2016 for a total transaction value of $73 million ($67 million for asset consideration and $6 million from adjustment of costs). No gain or loss was recognized.

Other Discoveries Offshore Israel Our development plan for the Dalit field (36% 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.

In July 2016, the Petroleum Commissioner of Israel deemed our Dolphin 1 (39.66% operated working interest) 2011 natural gas discovery to be non-commercial. As a result, we recorded exploration expense of $26 million in 2016 due to the expiration of our exploration license.

Asset Impairments During 2016 and 2015, we recorded impairment expense of $88 million and $36 million, respectively, related to offshore Israel properties. See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

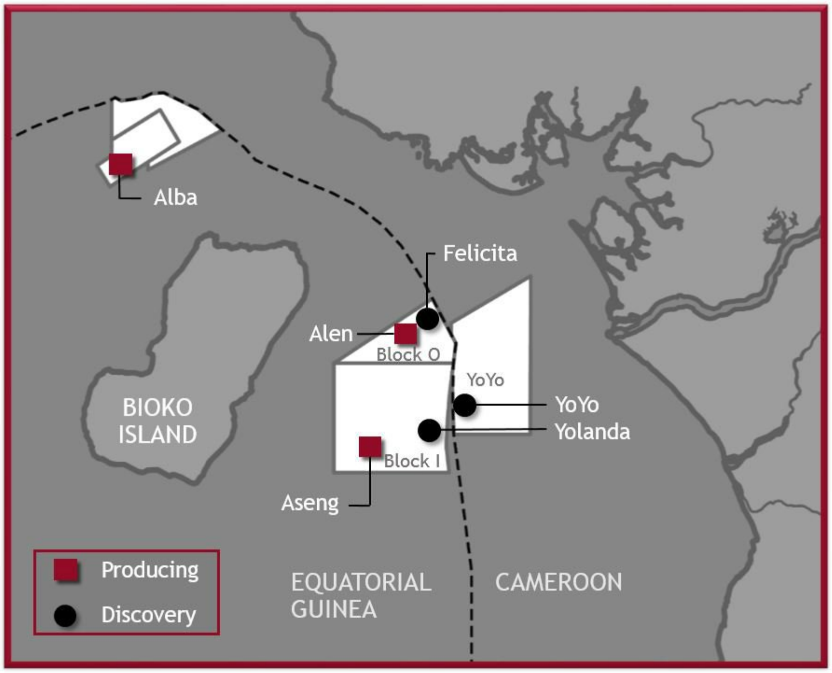
Israel Natural Gas Framework and Regulatory Environment We are subject to certain fiscal, antitrust and other regulatory challenges in Israel. These challenges have been addressed with the enactment of a comprehensive regulatory natural gas framework by the Government of Israel. See Regulations – Israel Natural Gas Framework and Item 1A. Risk Factors – *Our Eastern Mediterranean natural gas marketing activities bear certain geopolitical, regulatory, economic and financial risks that could adversely impact our ability to monetize our Israel and Cyprus natural gas assets.*

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

During 2015, we submitted a Declaration of Commerciality and in mid-2016, 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 Aphrodite field that, as currently planned, would deliver natural gas to potential customers in Cyprus and Egypt.

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 mining concession, offshore Cameroon, and one block offshore Gabon. In West Africa, our working 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 65 MBoe/d of sales volumes in 2016 and represented approximately 16% of total consolidated sales volumes. At December 31, 2016, Equatorial Guinea represented approximately 9% of total proved reserves. We held approximately 118,000 net developed acres and 10,000 net undeveloped acres in Equatorial Guinea, 168,000 net undeveloped acres in Cameroon, and 403,000 net undeveloped acres in Gabon at December 31, 2016.

Locations of our operations in Equatorial Guinea and Cameroon, as of December 31, 2016 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 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. In late 2016, the Aseng field reached several milestones including cumulative crude oil production of 80 MMBbls since coming online in 2011. We also completed the first major turnaround since production commenced. During 2016, the Aseng Field produced approximately 9 MBoe/d, net.

The Aseng FPSO is designed to act as a crude oil production hub, as well as 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 and safe performance, averaging over 99% production uptime.

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 8 MBoe/d, net, during 2016. In December 2016, Alen surpassed the 30 MMBbls cumulative gross production milestone. This accomplishment was achieved with a remarkable safety record of over 900 days without a recordable or lost time incident.

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

Alba Field Alba is a natural gas and condensate field located offshore, Equatorial Guinea (35% non-operated working interest, 34% revenue interest), which has been producing since 1991. Operations include the Alba field and related production and condensate storage facilities, an 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. The LPG processing plant and the methanol plant are located on Bioko Island, Equatorial Guinea. During 2016, the Alba field produced an average of 55 MBoe/d, net, reflecting 48 MBoe/d attributable to total sales volumes and 7 MBoe/d attributable to an equity investee.

During 2016, we along with the Alba field operator completed the Alba B3 compression project. Adding a compression platform to Alba is expected to extend the field life, and resulted in positive proved reserves revisions of 10 MMBoe at December 31, 2016.

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 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. In the first half of 2016, we completed scheduled turnaround activities for both the AMPCO methanol plant and the Alba LPG plant.

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.

Other Block O & I Projects In 2016, we analyzed, interpreted and evaluated acquired 3D seismic data across Blocks O and I. We determined that certain discoveries were impaired in the current forward outlook for crude oil prices and charged $468 million of capitalized exploratory well cost to exploration expense. We believe that the acreage attributable to the properties is currently subject to Blocks O and I PSCs which expire in 2036 and 2034, respectively.

Cameroon We have an interest in approximately 168,000 undeveloped acres offshore Cameroon in our YoYo mining concession (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, as well as to convert the YoYo mining concession to a PSC, which will provide a more robust framework directly related to oil and gas operational activities. We have completed reprocessing of 3D seismic data over our YoYo mining concession and are currently evaluating the data.

In 2016, we relinquished our acreage position in the Tilapia block (46.67% operated working interest), which covered an area of approximately 916,000 gross acres, to the Cameroon government and have exited this block. There was no significant impact to our 2016 financial results as dry hole costs relating to the Cheetah exploration well were expensed in 2015.

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) and 2008 Felicita discovery (Block O), offshore Equatorial Guinea, the YoYo discovery, offshore Cameroon, as well as natural gas from our Aseng and Alen fields.

A natural gas development team is working with both governments to evaluate natural gas monetization concepts at Bioko Island. Our current development concept provides for subsea tieback of Blocks I and O discoveries to the Alen platform. In third quarter 2016, a data exchange agreement for the 2007 Yolanda discovery (Block I) and 2007 YoYo discovery was executed between the governments of Equatorial Guinea and Cameroon. The execution of the agreement marks a significant milestone as a first step towards unitization of any cross border resources.

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 during second quarter 2016 and is currently being processed. Final product delivery is anticipated early 2017.

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

Other International

Our other international operations contributed no sales volumes for 2016 and had no proved reserves at December 31, 2016.

Offshore Falkland Islands In 2015, we experienced material operational issues with a drilling rig while drilling the Humpback well. The same drilling rig was scheduled to drill another prospect but due to significant safety and operational concerns, the drilling contract was terminated in first quarter 2016. As a result, we expensed $41 million of capitalized rig costs relating to pre-drill activities which is reflected in other operating expense, net, in the consolidated statements of operations.

We have been working closely with our partners and the Falkland Islands Government to evaluate a path forward for our Rhea prospect, located in the North Falkland Basin adjacent to a third party's 2010 Sea Lion discovery, and in 2016, we received a three-year extension for this license. We also held certain other licenses located in the South Falkland Basin and following completion of our geological assessment, we exited all licenses outside of PL-001, which contains the Rhea prospect, which resulted in $25 million undeveloped leasehold impairment expense in 2016.

An Argentine court has initiated a criminal investigation against Noble Energy and other oil and gas companies regarding their exploration activities offshore Falkland Islands. The court has also issued a preservation order against the relevant companies to preserve assets in the event of any judgment. The investigation is premised on Argentina's claim that the Falkland Islands are a part of its territory. Argentina does not recognize the United Kingdom's sovereignty over the Falkland Islands or the Falkland Islanders rights to exploit their natural resources. The Falkland Islands are part of the United Kingdom's overseas territories and are afforded full self-governance. Our concessions are with the Falkland Islands Government and we do not believe that Argentina has any authority over our operations in the Falkland Islands.

Offshore Suriname In October 2015, we acquired a non-operated 20% working interest in Block 54 offshore Suriname in the Atlantic Ocean via farm-in from Tullow Oil plc (Tullow). Tullow is the operator with a 30% interest. We have acquired and processed 3D seismic information and are currently interpreting data. We currently anticipate participating in drilling activities in late 2017.

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.

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.

The operator of the MacCulloch field has notified working interest owners that the scope and magnitude of decommissioning activities has been revised downward, resulting in a potential adjustment of the project timeline with lower field abandonment costs. As of December 31, 2016, we had a total asset retirement obligation of $85 million related to this remediation project. As the operator moves beyond the initial decommissioning phase, we will continue to monitor the status and costs of the project and will adjust our estimate accordingly.

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, environmental analysis 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 36 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 2016 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 2016, 2015, and 2014, we retained NSAI to perform audits of proved reserves. The reserves audit for 2016 included a detailed review of nine of our major onshore US, deepwater Gulf of Mexico 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. The reserves audit for 2014 included a detailed review of eight of our major fields and covered approximately 88% of total proved reserves.

In connection with the 2016 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 Regulation S-X Rule 4-10(a) 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, 2016, 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, 2016, on a quantity basis, the NSAI field estimates ranged from 3.1 MMBoe or 2% above to 6 MMBoe or 7% below 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, 2016 were, in the aggregate, approximately 27.9 MMBoe, or 2%.

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,		
	2016	2015	2014
(MMBoe)			
Proved Reserves Beginning of Year	1,421	1,404	1,406
Revisions of Previous Estimates	64	(216)	21
Extensions, Discoveries and Other Additions	179	100	120
Purchase of Minerals in Place	4	269	—
Sale of Minerals in Place	(77)	(6)	(33)
Production	(154)	(130)	(110)
Proved Reserves End of Year	1,437	1,421	1,404

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 included the following:

- changes for the year ended December 31, 2016 include positive revisions of 43 MMBoe for the DJ Basin, 42 MMBoe for the Marcellus Shale, 11 MMBoe for the Permian Basin, 6 MMBoe for deepwater Gulf of Mexico, 5 MMBoe for other onshore US and 10 MMBoe for 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;
- changes for the year ended December 31, 2015 include negative revisions of 307 MMBoe due to lower commodity prices, downward revisions of 9 MMBoe and 5 MMBoe for the DJ Basin and Eagle Ford Shale, respectively, primarily due to current drilling and development plans in the DJ Basin and expected reserve recovery from existing producing wells in the Eagle Ford Shale, and downward revisions of 3 MMBoe due to natural field decline from the Mari-B field,

offshore Israel; offset by positive performance revisions of 81 MMBoe for the Marcellus Shale, 17 MMBoe for the Permian Basin and 10 MMBoe for Alba field; and

- changes for the year ended December 31, 2014 included positive performance revisions of 18 MMBoe for the Marcellus Shale, 4 MMBoe for deepwater Gulf of Mexico, 4 MMBoe for Alba field, and 3 MMBoe for the Tamar field; offset by a downward revision of 8 MMBoe for the DJ Basin primarily due to planned reduction in pace of drilling activity due to lower commodity prices.

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 included the following:

- changes for the year ended December 31, 2016 include increases of 83 MMBoe in the DJ Basin, 42 MMBoe in the Marcellus Shale, 33 MMBoe in the Permian Basin and 21 MMBoe in the Eagle Ford Shale, all associated with our horizontal drilling programs;
- changes for the year ended December 31, 2015 include increases of 86 MMBoe in the DJ Basin and 14 MMBoe in the Marcellus Shale associated with our horizontal drilling programs; and
- changes for the year ended December 31, 2014 included increases of 48 MMBoe in the DJ Basin, 62 MMBoe in the Marcellus Shale, and 10 MMBoe deepwater Gulf of Mexico primarily attributable to sanction of the Dantzler development.

Approximately 75% of our 2017 capital program is allocated to onshore US, primarily in the DJ Basin, Delaware Basin and Eagle Ford Shale, and over 20% is allocated to offshore Israel. In turn, we expect that future reserves additions will primarily come from our development projects onshore US 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 and Other Exploration Expenditures.

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

- an increase of 4 MMBoe of NGL reserves primarily resulting from our Marcellus Shale acreage exchange in 2016; and
- the acquisition of additional acreage, primarily in the Eagle Ford Shale and Permian 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 included the following:

- a reduction of 36 MMBoe in Israel driven by our 3.5% sale of Tamar working interest, divestment of 29 MMBoe in the Marcellus Shale driven by our asset exchange, and other smaller divestments in onshore US resulting in a reduction of 12 MMBoe in 2016;
- the sale of onshore US assets in 2015; and
- the sale of onshore US and China assets in 2014.

See Items 1. and 2. Business and Properties and Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions, Divestitures and Merger.

Production See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Revenues – Oil, Gas and NGL Sales 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, 2016, our PUDs totaled 158 MMBbls of crude oil and condensate, 1.4 Tcf of natural gas, and 94 MMBbls of NGLs for a total of 486 MMBoe, or 34% of proved reserves. Changes in PUDs that occurred during the year are summarized below:

	United States	Israel	Equatorial Guinea	Total
(MMBoe)				
Proved Undeveloped Reserves Beginning of Year	344	71	70	485
Revisions of Previous Estimates	32	—	—	32
Extensions, Discoveries and Other Additions	166	—	—	166
Purchase of Minerals in Place	—	—	—	—
Sale of Minerals in Place	(22)	(7)	—	(29)
Conversion to Proved Developed	(98)	—	(70)	(168)
Proved Undeveloped Reserves End of Year	422	64	—	486

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 32 MMBoe in the US for 2016 included:

- 53 MMBoe positive revisions primarily in the DJ Basin, Marcellus Shale and Permian Basin due to current drilling and development plans;

offset by:

- negative revisions of 21 MMBoe due to lower commodity prices.

Extensions, discoveries and other additions include addition of proved reserves through additional drilling or the discovery of new reservoirs in proven fields. During 2016, we recorded the following additions as a result of successful expansion of our extended reach lateral well programs:

- 76 MMBoe in the DJ Basin;
- 31 MMBoe in the Permian Basin;
- 19 MMBoe in the Eagle Ford Shale; and
- 40 MMBoe in the Marcellus Shale.

Conversion to proved developed reserves included the following transfers:

- 26 MMBoe in the DJ Basin;
- 1 MMBoe in the Permian;
- 25 MMBoe in the Eagle Ford Shale;
- 33 MMBoe in the Marcellus Shale;
- 13 MMBoe in deepwater Gulf of Mexico; and
- 70 MMBoe in the Alba Field, offshore Equatorial Guinea.

In 2016, we converted 98 MMBoe of our US PUDs, or 28% of our US PUDs 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, 2016 to be converted to proved developed reserves within five years of initial disclosure.

US PUDs Locations As of December 31, 2016, our US PUDs included:

- 199 MMBoe in the DJ Basin;
- 70 MMBoe in the Permian Basin;
- 92 MMBoe in the Eagle Ford Shale; and
- 61 MMBoe in the Marcellus 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, 2016, we had approximately 81 MMBoe of proved undeveloped reserves associated with DUC well locations related to our onshore US operations, approximately 40% and 30% of which are in the Marcellus Shale and the Eagle Ford Shale, respectively, and the remainder are in the DJ Basin and Permian Basin.

International PUDs Locations As of December 31, 2016, our international PUDs included 64 MMBoe in Israel primarily in the Tamar and Tamar Southwest fields, including PUDs of 29 MMBoe related to the Tamar Southwest field, which is awaiting government approval of the development plan. We expect these PUDs to be converted to proved developed reserves within five years of initial disclosure.

Development Costs Costs incurred to advance the development of PUDs were approximately $656 million in 2016, $1.5 billion in 2015, and $2.0 billion in 2014. A significant portion of costs incurred in 2016 related to the DJ Basin, deepwater Gulf of Mexico and Marcellus Shale development projects.

Estimated future development costs relating to the development of PUDs are projected to be approximately $1.1 billion in 2017, $0.9 billion in 2018, and $0.8 billion in 2019. 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. All PUD drilling locations are scheduled to be drilled prior to the end of 2021. Initial production from these PUDs is expected to begin during the years 2017 to 2021.

PUDs with Negative PV10 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. Although our PUD reserves meet the SEC definition, this prescribed calculation can result in some PUDs having negative present worth, meaning while we have positive cash flows, the rate of return is lower than 10%.

At December 31, 2016, we had 133 well locations, primarily located in the DJ Basin and Marcellus Shale, with a negative present worth when discounted at 10% and based on SEC prices.

Although these PUD reserves had a negative present worth when discounted at 10%, they generated positive future net revenues.

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 these reserves within five years of initial disclosure. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Outlook – 2017 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 – Supplementary Oil and Gas Information (Unaudited) for additional information regarding estimates of crude oil, natural gas and NGL 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	Natural Gas MMcf	NGLs MBbl	Crude Oil & Condensate Per Bbl	Natural Gas Per Mcf	NGLs Per Bbl	Per BOE
Year Ended December 31, 2016							
United States							
DJ Basin	20,342	82,431	7,651	$ 40.85	$ 2.80	$ 14.66	$ 3.43
Marcellus Shale	431	177,872	3,094	28.25	1.68	16.34	0.90
Other US	15,572	62,017	9,087	38.26	2.42	14.65	6.26
Total US	36,345	322,320	19,832	39.59	2.11	14.92	3.57
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 [2]	9,415	85,987	—	43.54	0.27	—	4.40
Total Consolidated Operations	45,900	511,115	19,832	40.39	2.42	14.92	$ 3.59
Equity Investee [3]	629	—	1,993	45.44	—	26.30	N/M
Total	46,529	511,115	21,825	$ 40.46	$ 2.42	$ 15.96	N/M
Year Ended December 31, 2015							
United States							
DJ Basin	20,909	85,369	6,910	$ 44.37	$ 2.53	$ 14.21	$ 5.51
Marcellus Shale	673	143,465	3,480	22.39	1.75	14.04	1.40
Other US	7,680	29,806	3,705	42.83	2.56	13.25	6.07
Total US	29,262	258,640	14,095	43.46	2.10	13.91	4.28
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 [2]	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	433,438	14,095	45.00	2.44	13.91	$ 4.43
Equity Investee [3]	554	—	1,850	48.85	—	28.40	N/M
Total	41,441	433,438	15,945	$ 45.05	$ 2.44	$ 15.59	N/M
Year Ended December 31, 2014							
United States							
DJ Basin	18,209	75,039	6,072	$ 87.86	$ 4.11	$ 34.51	$ 6.00
Marcellus Shale	239	95,564	1,812	69.50	3.57	31.67	1.55
Other US	5,845	18,211	532	95.84	4.35	32.14	7.40
Total US	24,293	188,814	8,416	89.60	3.86	33.75	5.33
Israel							
Tamar Field	109	79,828	—	89.62	5.68	—	2.81
Other Israel	—	4,539	—	—	3.52	—	N/M
Total Israel	109	84,367	—	89.62	5.57	—	3.84
Equatorial Guinea [2]	12,191	88,833	—	94.61	0.27	—	5.44
China	788	—	—	103.74	—	—	8.53
United Kingdom	159	56	—	102.02	16.26	—	N/M
Total Consolidated Operations	37,540	362,070	8,416	91.58	3.38	33.75	$ 5.31
Equity Investee [3]	605	—	1,934	96.53	—	62.89	N/M
Total	38,145	362,070	10,350	$ 91.65	$ 3.38	$ 39.19	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) 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 the LPG plant in Equatorial Guinea.

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

At December 31, 2016, our operated properties accounted for the majority 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, 2016 was as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	3,974	3,628	3,821	3,501	7,795	7,129
Israel	—	—	8	3	8	3
Equatorial Guinea	5	2	21	8	26	10
Total	3,979	3,630	3,850	3,512	7,829	7,142

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) held at December 31, 2016 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
(thousands of acres)				
United States				
Onshore	902	768	694	430
Deepwater Gulf of Mexico	100	51	282	192
Total United States	1,002	819	976	622
International				
Israel	185	78	284	116
Equatorial Guinea (1)	284	118	26	10
Suriname	—	—	2,095	419
Newfoundland	—	—	1,942	525
Gabon	—	—	671	403
Cyprus	—	—	95	33
Falkland Islands (2)	—	—	280	210
Cameroon	—	—	168	168
United Kingdom	2	—	4	1
Total International	471	196	5,565	1,885
Total	1,473	1,015	6,541	2,507

(1) Undeveloped acreage excludes an exploration lease totaling approximately 55,000 gross (19,000 net) acres which expired in 2016. We are negotiating with the government of Equatorial Guinea to extend the lease.

(2) Following completion of our geological assessment in 2016, we exited all licenses in the Falklands Islands, outside of License PL-001, which contains the Rhea prospect, thereby reducing our acreage position by approximately 10 million, gross, and 3 million, net, acres.

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.

Future Acreage Expirations If production is not established or we take no other action to extend the terms of the leases, licenses, or concessions, undeveloped acreage will expire over the next three years as follows. No material quantities of PUD reserves were associated with the expiring acreage.

	Year Ended December 31,					
	2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net
(thousands of acres)						
Onshore US	156	103	143	41	113	73
Deepwater Gulf of Mexico	1	1	76	55	36	25
Falkland Islands	—	—	—	—	280	210
Suriname	—	—	2,095	419	—	—
Gabon	—	—	671	403	—	—
Total	157	104	2,985	918	429	308

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, 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
Falkland Islands	—	0.4	0.4	—	—	—	0.4
Cameroon	—	0.5	0.5	—	—	—	0.5
Total	1.5	4.9	6.4	212.8	—	212.8	219.2
Year Ended December 31, 2014							
United States	1.5	3.1	4.6	319.1	0.7	319.8	324.4
Total	1.5	3.1	4.6	319.1	0.7	319.8	324.4

In addition to the wells drilled and completed in 2016 included in the table above, wells that were in the process of drilling or completing at December 31, 2016 were as follows:

	Exploratory[(1)]		Development[(2)]		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	5	4.0	142	128.9	147	132.9
Israel	4	1.5	1	0.3	5	1.8
Equatorial Guinea	2	0.9	—	—	2	0.9
Cameroon	1	1.0	—	—	1	1.0
Cyprus	2	0.7	—	—	2	0.7
Total	14	8.1	143	129.2	157	137.3

(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.

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.

Oil Spill Response Preparedness In the US, we maintain membership in Clean Gulf Associates (CGA), a nonprofit association of production and pipeline companies operating in the Gulf of Mexico, and Marine Spill Response Corporation, the largest, dedicated oil spill and emergency response organization in the US. For well capping and containment services we have contracted with HWCG, which has contracted with Helix Energy Solutions Group (HESG) for the provision of subsea intervention, containment, capture and shut-in capacity for deepwater Gulf of Mexico exploratory wells.

Internationally, we maintain membership in Oil Spill Response Limited (OSRL), an industry-owned cooperative. We also maintain agreements internationally with National Response Corporation and PolyEco Group, which provide leased response equipment as well as supplemental oil spill response services. Additionally, in Equatorial Guinea, we are members of the Oil and Gas Operators Emergency Resource Allocation Group which shares equipment and resources in the event of a spill.

Domestic Marketing Activities Crude oil, natural gas, condensate and NGLs produced onshore US and in the deepwater 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.

Certain onshore US areas in which we operate have had minimal infrastructure in place for the processing and transportation of our production. Company and third party infrastructure projects that came online in 2015 and 2016 have improved flow assurance. Future projects, such as near our Marcellus Shale assets in the Northeast, coming online in the next few years are expected to continue to enhance transportation of production to end markets.

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) under a long-term sales contract through 2018. 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 gathering, processing and transportation contracts for some of our onshore US production, with remaining terms of one to 32 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 2016, 2015, and 2014, we incurred expense of approximately $58 million, $33 million, and $16 million, respectively, related to volume deficiencies and/or unutilized commitments primarily in our onshore US 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. 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 Israel Electric Corporation (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 for 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 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, 2016, a total of approximately 5.7 Tcf, gross (1.847 Tcf, net), of natural gas remained to be delivered under the contracts. As of December 31, 2016, we have recorded 2.0 Tcf, net, of proved natural gas reserves, including proved developed reserves of 1.6 Tcf, net, and PUD reserves of 384 Bcf, net, for offshore Israel. Based on current production levels and future development plans, our available quantities of proved reserves are more than sufficient to meet near-term delivery commitments.

We are also engaged in marketing activities related to the Leviathan natural gas project. See Eastern Mediterranean (Israel and Cyprus), above.

Significant Purchasers Glencore Energy and Shell Trading (US) (Shell) were the largest single purchasers of our 2016 production.

Glencore purchased our share of crude oil and condensate production from the Alba, Aseng and Alen fields in Equatorial Guinea. Sales to Glencore Energy accounted for 12% of 2016 total crude oil, natural gas and NGL sales, or 22% of 2016 crude oil sales.

Shell purchased crude oil and condensate domestically from the deepwater Gulf of Mexico, the DJ Basin and the Marcellus Shale. Sales to Shell accounted for 13% of our 2016 total crude oil, natural gas and NGL sales, or 24% of crude oil sales.

No other single purchaser accounted for 10% or more of crude oil, natural gas and NGL sales in 2016. 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.

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 National Infrastructures, Energy and Water Resources 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;
- the Ministry of Energy, Commerce, Industry and Tourism which regulates our exploration and development activities offshore Cyprus; and
- the Department of Mineral Resources which regulates our exploration activities offshore the Falkland Islands.

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 deepwater 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 (RCRA), 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 deepwater Gulf of Mexico; and
- the Department of Transportation (DOT), which has certain authority over the transportation of products, equipment and personnel necessary to our onshore US and deepwater 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 As a developer, owner and operator of crude oil and natural gas properties, we are subject to various federal, state, local and foreign host country laws and regulations relating to the discharge of materials into, and the protection of, the environment. We must 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. 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.

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.

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 we have, to date, expended material amounts in connection with such activities or 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. In January 2017, for example, the FWS announced that it was listing the Rusty Patched Bumble Bee as endangered under the ESA. Conservation measures are currently not known but could have an impact on the timing of certain of our operations in the Marcellus Shale. Listing of the Lesser Prairie Chicken likewise could impact our operations in the Permian 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 that it has undertaken a new status review of the Lesser Prairie Chicken to determine whether listing is still warranted. That assessment is expected to be completed in the summer of 2017.

In May 2015, the US Environmental Protection Agency and the US Army Corps of Engineers jointly released a final rule that is meant to define more precisely which water bodies are and are not subject to the Clean Water Act (the Clean Water Rule). Among other things, the Clean Water Rule defines the intermittent, ephemeral, and man-altered streams to be protected and specifies when federal jurisdiction may be extended from a covered water to nearby waters. While the agencies have claimed that the new requirements are narrower than existing regulation, the Clean Water Rule has generated substantial controversy. Several court challenges have been filed, and in October 2015, the rule was stayed by the U.S. Court of Appeals for the Sixth Circuit, pending its review of legal challenges to the rule. To the extent that the Clean Water Rule requires more detailed studies of site conditions, or results in an expansion of federal jurisdiction over streams and wetlands, our costs may increase, especially with respect to spill prevention, storm water management, and wetlands permitting. We are continuing to monitor the challenges and to evaluate the impact of the new rule on our operations.

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. To date, those rules have had minimal impact on our business since the reduction of 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.

In March 2014, the previous US Administration released a Strategy to Reduce Methane Emissions that includes consideration of both voluntary programs and targeted regulations for the oil and gas sector. Towards that end, the EPA released five draft white papers on methane emissions, volatile organic compound (VOC) emissions, and emission mitigation measures for natural gas compressors, hydraulically fractured oil wells, pneumatic devices, well liquids unloading facilities, and natural gas production and transmission facilities. After issuing a proposed rule in 2015, the EPA issued a final rule in May 2016 that sets additional standards for methane and VOC emissions from new and modified oil and gas production sources. The new rule will require operators of oil and gas properties to monitor and repair leaks, capture gas from the completion of hydraulically fractured wells, limit emissions from new and modified pneumatic pumps, and limit emissions from several types of equipment used at gas transmission compressor stations, including compressors and pneumatic controllers. An accompanying EPA rule will require oil and natural gas sites within one-quarter mile to be aggregated as a single source for purposes of air permitting, 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, in November 2016 the BLM issued final rules for reducing venting and flaring of methane gas on public lands. The previous US Administration's goal was to reduce methane emissions from the oil and gas industry by 40-45% by 2025 as compared to 2012 levels. Challenges to the new BLM rules have been filed in federal court. It also bears noting that substantially all of our onshore US 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. See Hydraulic Fracturing, below.

In 2014, by executive order, Colorado Governor Hickenlooper created the Task Force on State and Local Regulation of Oil and Gas Operations (Task Force) for the purpose of recommending policies and legislation. The 21-member Task Force, which included a Noble Energy representative, concluded its activities on February 27, 2015. The Task Force sent nine recommendations to the Governor. The recommendations sought to balance land use issues among communities and oil and gas operators and allow reasonable access to private mineral rights. Three recommendations were approved by the legislature, and in January 2016 state regulators approved two rules addressing siting of large oil and gas operations in urban areas and coordination of drilling with local governments. We currently are evaluating the new rules.

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 18. Commitments and Contingencies.

Pennsylvania Pennsylvania's Act 13 of 2012 (Act 13) represented the first comprehensive legislation regarding the development of the Marcellus Shale in Pennsylvania. Act 13, among other things, enacted stronger environmental standards;

established impact fees, which are set based on a multi-year fee schedule and the average sales price of natural gas; increased the notice distance for unconventional well permit applications from 1,000 feet to 3,000 feet; extended the setback distance for unconventional wells from 200 feet to 500 feet; and increased the distance and duration of presumed liability for water pollution to 2,500 feet from a well site and twelve months after well drilling, completion, stimulation or alteration. In addition, Act 13 imposed spill prevention requirements applicable to well site construction, wastewater transportation, and gathering lines.

Act 13 has been the subject of multiple challenges in the Pennsylvania courts. In 2013 for example, the Pennsylvania Supreme Court invalidated the portions of Act 13 providing for statewide zoning and state waivers of the setback requirements in Pennsylvania's Oil and Gas Act. In 2014, moreover, the Pennsylvania Commonwealth Court invalidated Act 13's provisions allowing the state to review local drilling rules. These court decisions have the effect of giving local communities in Pennsylvania more authority to regulate oil and gas operations, which could make it more difficult to develop our Marcellus Shale acreage in some municipalities.

Furthermore, the state has finalized new rules for surface operations at oil and gas sites that, among other things, would increase public participation in the permitting process, increase mitigation obligations and require surveys for abandoned wells. On October 8, 2016, the Pennsylvania Department of Environmental Protection issued the final rule amending Pennsylvania Code Chapter 78a revising requirements for surface activities related to unconventional oil and gas operations. The final rule increases requirements for permitting, waste handling, water management and restoration, surface reclamation, and requirements related to abandoned and orphaned wells. In November 2016, a Pennsylvania state court issued an opinion requiring the enforcement of certain portions of the new rule while the court considers legal challenges to the rule brought by an industry group. These regulations may increase operating costs and cause delays.

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 May 2013, the Texas Railroad Commission (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.

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

US Offshore Regulatory Developments 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. Although the final rule incorporates some of the changes recommended by the oil and gas industry, it imposes a number of new requirements relating to well design, well control, casing, cementing, real-time well monitoring and subsea containment. For example, the new rule requires double sets of shear rams on all deepwater blowout preventers (BOPs), periodic inspections of BOPs and outside audits of equipment, and real-time well monitoring requirements. The new rule will likely increase the costs associated with well design, drilling and completion operations, as well as ongoing monitoring costs for our wells in the Gulf of Mexico. The final rule went into effect on July 28, 2016.

On March 17, 2016, the BOEM proposed a new 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. The comment period for the proposed rule expired June 20, 2016.

Additionally, 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 is extending the implementation timeline for six months in certain circumstances. 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. We are currently evaluating the expansion alternatives and assessing any potential impact on our operations in the Gulf of Mexico.

See Item 1A. Risk Factors – *We are subject to increasing governmental regulations and environmental requirements that may cause us to incur substantial incremental costs.*

Israel's Natural Gas Policy and Antitrust Authority The Israel Natural Gas Framework, as adopted by the Government of Israel, provides clarity on numerous matters concerning resource development, including certain fiscal, antitrust and other regulatory matters, which we will rely upon to support a final investment decision and proceed with the development of these resources while ensuring economic benefits to the state of Israel and its citizens. The Framework provides for the reduction of our ownership interest in Tamar to 25% by year-end 2021, while enabling the marketing of Leviathan natural gas to Israeli customers. In second quarter 2016, the Government of Israel adopted a new economic stability clause which does not remove the possibility of future adverse legislation but does provide for project economic stability in the event of certain future adverse actions.

Impact of Dodd-Frank Act Section 1504 On June 27, 2016, the SEC adopted resource extraction issuer payment disclosure rules under Section 1504 of the Dodd-Frank Act that will require resource extraction companies, such as us, to publicly file with the SEC information about the type and total amount of payments made to a foreign government, including subnational governments (such as states and/or counties), or the U.S. federal government for each project related to the commercial development of crude oil, natural gas or minerals, and the type and total amount of payments made to each government. Reporting and disclosure will be required annually beginning with the 2018 fiscal year.

Hydraulic Fracturing

Concerns The practice of hydraulic fracturing, especially the hydraulic fracturing processes associated with drilling in shale formations, is the subject of significant focus among some environmentalists and regulators. Concerns over potential hazards associated with the use of hydraulic fracturing and its impact on the environment and, potentially, the general public health, have been raised at local, state and federal levels of government in the US and internationally. Hydraulic fracturing requires the use and disposal of water, and public concern has been growing over its possible effects on drinking water supplies, as well as the adequacy of both water supply sources and disposal methods.

Our Operations Hydraulic fracturing techniques have been used by the industry since 1947, and, currently, more than 90% of all crude oil and natural gas wells drilled in the US employ hydraulic fracturing. 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.

Where possible, we strive to procure non-hydrologic water (water that is not connected to a natural surface stream) for use in hydraulic fracturing; a large proportion of our water is from non-tributary sources, such as deep ground water. In the DJ Basin, we are in the process of securing additional water rights in support of our drilling program, and we engage in significant water recycling efforts in both the DJ Basin and Marcellus Shale. 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.

Studies and Potential Rulemaking Although hydraulic fracturing is regulated primarily at the state level, governments and agencies at all levels from federal to municipal are studying it and evaluating the need for further requirements. For example, in 2011, the US Secretary of Energy formed the Shale Gas Production Subcommittee (Subcommittee), a subcommittee of the Secretary of Energy Advisory Board. The Subcommittee issued final recommendations in November 2011 that included better communications with the public, better air quality controls, protection of water supply and quality, disclosure of fracturing fluid composition, reduction of diesel fuel use, continuous development of best practices, and federal sponsorship of research and development with respect to unconventional gas.

In addition, the US Department of Energy's National Energy Technology Laboratory (NETL) is conducting a comprehensive assessment of the environmental effects of shale gas production at two industry-provided Marcellus Shale test sites in southwestern Pennsylvania. Goals include:

- documentation of environmental changes that are coincident with shale gas production;
- development of technology or management practices that mitigate any unintended environmental changes; and
- development of monitoring technologies to (1) assess the impact of shale gas production on air quality and (2) determine if zonal isolation between producing formations and drinking water aquifers is maintained after hydraulic fracturing.

We are monitoring the results of the NETL study in order to assess any potential impact to our onshore US development programs.

In June 2015, moreover, the US EPA issued its draft "Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources." At a high level, the agency states, "[it] did not find evidence that hydraulic fracturing mechanisms have led to widespread, systemic impacts on drinking water resources in the United States." The agency's Science Advisory Board (SAB) commented, however, that the agency's conclusions do not clearly describe the systems of interest (e.g., groundwater, surface water) nor the definitions of "systemic," "widespread," or "impacts." The SAB also raised a concern that the agency's conclusions do not reflect "the uncertainties and data limitations described in the body of the Report associated with such impacts." As a result, the EPA issued a final report concluding that fracturing "activities can impact drinking water resources under some circumstances." Among these are spills, leaks from pits, injection "into wells with inadequate mechanical integrity" and injection "directly into groundwater resources." The EPA also found "significant data gaps and uncertainties in the available data." We are monitoring whether the EPA's revised conclusions generate further agency activities.

Also on the regulatory front, the US BLM issued proposed regulations in 2012 for hydraulic fracturing on federal lands, which were withdrawn and then reissued on May 16, 2013. BLM's rules would affect drilling operations on the 700 million acres of federally-owned minerals administered by the BLM, as well as 56 million acres of Native American-owned minerals. A final rule was released in March 2015, and was immediately challenged in U.S. district court in Wyoming. The judge struck down the rule in July 2016, finding the BLM lacked statutory authority to promulgate the new regulations. The agency has appealed that ruling, with opening arguments to begin in March 2017.

Apart from its air regulations for newly fractured natural gas wells (see Regulations), the EPA developed new guidelines under the Safe Drinking Water Act regarding the issuance of permits for the use of diesel fuel as a component in hydraulic fracturing activities. The guidance outlines for EPA permit writers, where EPA is the permitting authority, requirements for diesel fuels used for hydraulic fracturing of wells, technical recommendations for permitting those wells, and a description of diesel fuels subject to EPA underground injection control permitting. Beyond that, the agency has solicited public comment on information reporting and disclosure for hydraulic fracturing. The EPA also has developed a rule addressing discharges of hydraulic fracturing wastewaters from oil and gas extraction facilities to public treatment works. In December 2016, the EPA extended the compliance deadline until August 2019.

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, Texas, West Virginia, and Pennsylvania) have developed such requirements. See Regulations. Beginning in 2012, a number of local communities in Colorado became interested in increasing regulatory requirements on oil and gas development. Ballot measures supporting restrictions or bans on the practice of hydraulic fracturing within their boundaries were passed in several municipalities. Challenges were brought against each of these bans in state district court and, in May 2016, the Colorado Supreme Court found that the local laws in question were preempted by existing state law and were therefore invalid.

In the future, however, should additional statewide or local Colorado initiatives be undertaken to regulate, limit or ban hydraulic fracturing or other facets of crude oil and natural gas exploration, development or operations, our business could be impacted, resulting in delay or inability to develop oil and gas reserves, reducing our long-term reserves, production and cash flow growth, and potentially having a negative impact on our stock price.

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 could lead to greater opposition, including litigation, to oil and gas activities utilizing injection wells for waste disposal. In the states where we operate, the regulatory agencies are evaluating possible modifications to the regulations of wastewater disposal through injection wells due to the potential for induced seismicity; however, there has not been any finalization or implementation of new regulations around this topic.

Public Disclosure Several states have issued regulations requiring disclosure of certain information regarding the components used in the hydraulic-fracturing process. In 2011, for example, the RRC adopted the Hydraulic Fracturing Chemical Disclosure rule, which requires companies to disclose, on a public registry, chemical ingredients used to hydraulically fracture wells in Texas. The registry, FracFocus.org, is operated jointly by the Interstate Oil & Gas Compact Commission and the Ground Water Protection Council. In December 2011, the COGCC adopted hydraulic fracturing fluid ingredient regulations requiring disclosure of all chemicals and establishing ways to protect proprietary information. The regulations allow disclosure through the FracFocus web site. The State of Wyoming also requires disclosure of the types and amounts of fracturing chemicals. In 2012, through Act 13, Pennsylvania established a requirement that operators submit information regarding hydraulic fracturing chemicals to FracFocus.org. Other states have proposed, or are considering, similar regulations which require specific disclosures by operators and/or outline requirements for construction and operation of wells and monitoring of well activity. We are currently providing disclosure information on FracFocus.org for all onshore US areas in which we operate.

Additional Information See:

- Items 1. and 2. Business and Properties – Regulations;
- Item 1A. Risk Factors; and
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Risk and Insurance Program.

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.

Geographical Data

We have operations throughout the world and manage our operations by region. Information is grouped into four components that are all in the business of crude oil, natural gas and NGL exploration, development and production: United States, Eastern Mediterranean, West Africa and Other International and Corporate. See Item 8. Financial Statements and Supplementary Data – Note 15. Segment Information.

Employees

As of December 31, 2016, we had 2,274 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; Canonsburg, Pennsylvania; and in Israel, Cyprus, Equatorial Guinea, and Cameroon.

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 onshore US 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 Permian 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 natural gas 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.nobleenergyinc.com.* Available on this website under “Investors – 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 “About Us – Corporate Governance”, 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 “Corporate Governance” 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 business 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 two years, following the significant decline that began in late 2014, crude oil prices, in particular, have been trading in a much lower range. While, in the second half of 2016, we 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.

Average commodity prices for 2016 fell below the already suppressed 2015 average prices, and, thus, continued to negatively impact our revenues, operating cash flows and profitability and adversely affected the price of our common stock. If commodity prices continue to trade at low or lower levels for an extended period, one or more of the following could occur:

- further 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;
- additional 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 2017 capital investment program, or significant reductions in 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, and/or ability to finance planned capital expenditures and operations;
- 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 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;
- limitations on our access to sources of capital, such as debt and equity; 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; and
- additional counterparty credit risk exposure on commodity hedges and joint venture receivables.

Our hedging arrangements in place will not fully mitigate the effects of commodity price volatility. Furthermore, in the current commodity price environment, we are less likely to hedge future revenues to the same extent as our historical and existing hedging arrangements. As such, our revenues will be more susceptible to commodity price volatility as our commodity price hedges settle and are not replaced.

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;
- new technologies that promote fuel efficiency and reduce energy consumption;
- developments in the global liquified natural gas (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;
- the long-term impact on the crude oil market of the use of natural gas as an alternative fuel for road transportation;
- 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;
- demand for electricity as well as natural gas used as fuel for electricity generation;
- fuel efficiency regulations, such as the Corporate Average Fuel Economy (CAFE) standards, and its impacts on crude oil demand as a transportation fuel;
- 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, such as occurred in 2015 and 2016, 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.

In the second half of 2016, we witnessed a modest improvement in commodity prices. If this trend continues, and if the commodity price recovery is robust, we expect industry exploration and production activities to increase, resulting in higher demand for oilfield services and supplies, which could result in 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.

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 Eastern Mediterranean discoveries bear certain geopolitical, regulatory, financial and technical challenges that could adversely impact our ability to monetize our Israel and Cyprus 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.

We are subject to certain regulatory provisions under the Israel Natural Gas Framework, as adopted by the Government of Israel, including a requirement to reduce our ownership in Tamar to 25% by the end of 2021. Our inability to sell-down interest at competitive market terms or to reduce our ownership to 25% within the time period required by the Framework, could result in a loss of proceeds due to selling our ownership at less than satisfactory terms. 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;
- delay or preclude closing of financing arrangements for our partners; and/or
- render future exploration and development projects uneconomic.

Each of our development options requires a multi-billion dollar investment and will take several years to complete. Failure of our partners to obtain financing on acceptable terms could result in a delay in these development projects.

Due to the scale of our Leviathan and Cyprus discoveries, realization of their full economic value depends on our ability to execute successful development scenarios for Leviathan and Aphrodite, the failure 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.

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.

Some of our major development projects entail significant capital expenditures and have long development cycle times. For example, in the Eastern Mediterranean, each of our natural gas development options requires a multi-billion dollar investment and spans multiple years from project sanction to production.

As a result, 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. Our partners are as susceptible to certain of the risk factors captured under Item 1A as we are, including, but not limited to, commodity price declines, fiscal regime changes, government project approval delays, regulatory changes, credit downgrades and regional conflict. If one or more of these factors negatively impacts our project partners' cash flows or ability to obtain adequate financing, it could result in a delay or cancellation of a project, resulting in a reduction of our reserves and production, negatively impacting the timing and receipt of planned cash flows and expected profitability.

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

We have significant international operations, with approximately 27% of our 2016 total consolidated sales volumes coming from our international operations in Israel and Equatorial Guinea. We also conduct exploration activities in 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 in other countries;
- 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;
- foreign exchange or repatriation restrictions;
- war, piracy, acts of terrorism or civil unrest;
- US and international monetary policies causing changes in the relative value of the US dollar as compared with the currencies of other countries in which we conduct business; and
- other hazards arising out of foreign governmental sovereignty over areas in which we conduct operations.

Such political and economic developments as mentioned above 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 itself issued guidance reports in October 2015 on Base Erosion and Profit Shifting (BEPS), an initiative which aims to standardize and modernize global tax policy and disclosure of financial and operational data with tax authorities. Adoption of BEPS's recommendations is widely expected by the majority of the foreign jurisdictions in which we operate and this 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.

In the US, certain measures have been proposed that would alter current tax expense on oil and gas companies, for example: the repeal of percentage depletion for oil and natural gas properties; the deferral of expensing intangible drilling and development costs (IDC); the inability to expense costs of certain domestic production activities; and a lengthening of the amortization period for certain geological and geophysical expenditures. It is likely that some of these proposals to increase tax expense on the oil and gas industry will continue to be reviewed by the US Congress in future years. The enactment of some or all of these proposals could have a significant negative impact on our capital investment, production and growth.

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 exploration 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;
- cause delay in or cancellation of development plans, which could also have a long-term negative impact on the quantities of proved reserves we record and inhibit future production growth;
- 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;
- restrict our ability to compete with imported volumes of crude oil or natural gas; and/or
- adversely affect the price of our common stock.

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

A significant portion of our production and revenue is highly concentrated and is generated from certain conventional deepwater fields. These fields, located in the Gulf of Mexico, offshore Eastern Mediterranean and offshore West Africa, contributed approximately 41% of our 2016 total consolidated revenues and 34% of our 2016 sales volumes, respectively, and are capital and resource-intensive.

Although we carry contingent business interruption insurance in these areas, 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, Permian Basin, Eagle Ford Shale and Marcellus Shale, and we expect to invest approximately $1.8 billion, or 75%, of our total capital investment program to development activities in these areas. Restrictions in land access, rapid changes in drilling and completion technology, lack of availability of downstream services, changes in regulations and other risks impacting these areas, as enumerated in the accompanying Risk Factors, can have immediate, significant negative impacts on our production, cash flows, profitability and financial position.

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.

Violent acts resulting in loss of life, destruction of property, environmental damage and pollution occur around the world. Many incidents are driven by civil, ethnic, religious or economic strife. In addition, the number of incidents attributed to various terrorist or extremist organizations has increased significantly. Certain countries within the Middle East, including Syria, Libya, Iraq and Yemen, 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 our curtailing 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 world 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 rig, 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 and/or mechanical failure at terminals or other onshore delivery points;
- 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;

- spills, leaks or discharges of fluids used in or produced in the course of operations, especially those that reach surface water or groundwater; and
- security breaches, cyber attacks, piracy or terroristic acts.

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, deepwater Gulf of Mexico, and the Marcellus Shale;
- winter storms and snow which could affect our operations in the DJ Basin and Marcellus Shale;
- 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, Marcellus Shale and Texas;
- harsh weather and rough seas offshore the Falkland Islands and Newfoundland, 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 oil and 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.

Onshore, we are currently planning to invest significant amounts of capital to continue development of our onshore US unconventional resources. 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.

Offshore, we are progressing the first phase development of the Leviathan natural gas project, planning the Tamar expansion project and evaluating development options for our Katmai discovery. 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 they are constructed.

Costs of drilling, completing and operating wells can be uncertain, and cost factors can adversely affect the economic viability of a project. Inability to drill profitably or market our production, could decrease our current cash flows and reduce the return on our investment.

Exploratory drilling may not result in the discovery of commercially productive reservoirs.

Exploration success within existing or new frontier areas provides for growth in production and reserves. Exploratory drilling requires significant capital investment and does not always result in commercial quantities of hydrocarbons or new development projects.

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.

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:

- lower commodity price outlook;
- title problems;
- near-term lease expiration;
- decisions impacting allocation of capital;
- compliance with environmental and other governmental requirements;
- availability of market, or costs to develop infrastructure;
- increases in the cost of, or shortages or delays in the availability of, drilling rigs, equipment and qualified personnel;
- unexpected drilling conditions;
- pressure or other irregularities in formations;
- equipment failures or accidents; and
- adverse weather conditions.

In addition, companies seeking new reserves often face more difficult environments, such as oil sands, deepwater, or ultra-deepwater, and often need to develop or invest in new technologies. This environment increases cost as well as drilling risk.

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.

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. Violations of environmental laws and regulations could result in fines or required mitigation activities. 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 18. Commitments and Contingencies.

In addition, in certain areas, legal enforcement may be impacted by significant new incentives for whistleblowers. Violations of any laws or regulations caused by either failure of our internal controls related to regulatory compliance or failure of our employees to comply with our internal policies could result in substantial civil or criminal fines, sanctions, or loss of our license to operate. In addition, as we continue to pursue exploration opportunities with new partners in new geographical locations, our ability to mitigate risks of actual or alleged violations could decrease. Actual or alleged violations of US and international laws could damage our reputation, be expensive to defend, and impair our ability to do business.

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, there have been recent efforts to challenge and change individual and/or corporate taxation. These efforts, if they gain political traction, 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 trend toward populism, coupled with the recent change in US Administration, have resulted in uncertainty regarding potential changes in regulations, fiscal policy, social programs, domestic and foreign relations and international trade policies. For example, the new US Administration recently signaled a potential change in US relations with Russia and China, and signed an Executive Order to withdraw from the Trans-Pacific Partnership. Global uncertainty and/or reductions in global trade activities could contribute to slower economic growth which could negatively 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 recent election results are signaling increasing populist demands and rises in nationalism, which 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-development activity.

As new technologies have been applied to our industry in recent years, we have seen significant growth in non-OPEC crude oil and natural gas supply, particularly in the US. With this expansion of activity, opposition toward oil and gas drilling and development activity has been growing both in the US and globally.

Companies in our industry can be the target of opposition to development from certain stakeholder groups, including national and local governments and regulatory agencies. These anti-development efforts could be focused on limiting hydrocarbon development; reducing access to national and state government lands; delaying or canceling certain projects such as offshore drilling, shale development, and pipeline construction; limiting or banning the use of hydraulic fracturing; blocking activity in certain areas such as the Arctic; denying air-quality permits for drilling; and advocating for increased regulations on shale drilling and hydraulic fracturing. Potential changes in regulations, as signaled by the current US Administration, could intensify the risk of anti-development efforts as grass roots opposition efforts grow.

In addition, the use of social media channels can be used to cause rapid, widespread reputational harm.

Future anti-development efforts could result in the following:

- blocked development;
- denial or delay of permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering, processing or pipeline facilities;
- restrictions on the transportation of crude oil and natural gas;
- restrictions on the use of certain operating practices, such as hydraulic fracturing;
- reduced access to water supplies or restrictions on water disposal;
- limited access or damage to or destruction of our property;
- legal challenges or lawsuits;
- targeted activist shareholder campaigns;
- increased regulation of our business;
- damaging publicity about the Company;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Our need to incur costs associated with responding to these initiatives or complying with any new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

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

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and for compliance reporting. The use of mobile communication devices has increased rapidly. Industrial control systems such as SCADA (supervisory control and data acquisition) now control large scale processes that can include multiple sites and long distances, such as power generation and transmission, communications and oil and gas pipelines.

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, 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.

A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations in the following ways, among others:

- unauthorized access to seismic data, reserves information or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
- data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- data corruption or operational disruption of production infrastructure could result in loss of production, or accidental discharge;
- a cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt a development project, effectively delaying the start of cash flows from the project;
- a cyber attack on a third party gathering or pipeline service provider could prevent us from marketing our production, resulting in a loss of revenues;
- a cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;

- a cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices, and reduced revenues;
- a cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
- a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and
- business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common stock.

Our implementation of various controls and processes, including globally incorporating a risk-based cyber security framework, 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.

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.

For example, various recommendations with respect to unconventional gas have been issued by the Shale Gas Production Subcommittee, a subcommittee of the Secretary of Energy Advisory Board, and the US Department of Energy's National Energy Technology Laboratory is conducting a comprehensive assessment of the environmental effects of shale gas production.

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 reports and developed various rules and guidelines regarding hydraulic fracturing activities, and the Bureau of Land management, under the US Department of the Interior, which has issued final rules impacting hydraulic fracturing on federal lands. In addition, OSHA and NIOSH have authority to regulate certain workplace practices.

All of the states, as well as certain localities, where we operate have adopted or may adopt additional regulations on drilling activities in general or hydraulic fracturing in particular. For example, a number of local communities in Colorado have attempted to increase regulatory requirements on oil and 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 oil and gas 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 onshore US 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 onshore US, 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 onshore US areas and deepwater 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 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 production, thereby harming our business and, in turn, our results of operations, cash flows, and financial condition.

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 and natural gas 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 or state 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 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 portfolio.

Our entry into new exploration ventures in countries which have no history of hydrocarbon sector investment subjects us to risks.

We hold working interests in certain areas, each of which currently has minimal or no crude oil or natural gas production, and in certain cases, limited infrastructure, including offshore areas of Cyprus, Falkland Islands, Cameroon, Gabon, Suriname and Newfoundland. Our activities will be subject to risks including, among others:

- exploration activities in frontier areas may not result in commercially productive quantities of crude oil, natural gas and NGL reserves;
- remote locations make it more difficult and time-consuming to transport personnel, equipment and supplies;
- certain operating environments, such as offshore the Falkland Islands and Newfoundland, include harsh weather and rough seas which could limit seismic surveys and other exploration activities during certain periods;
- pandemics and epidemics, which may adversely affect our business operations through travel or other restrictions; and
- there have been numerous acts of piracy, kidnapping, civil strife, regional conflict, border disputes, cross-border violence, and war, as well as violence associated with corruption, drug trafficking and regime changes in certain areas.

These, and other risks, could be intensified if commercial quantities of crude oil or natural gas are discovered. In addition, 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.

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.

Indebtedness may limit our liquidity and financial flexibility.

At December 31, 2016, we had $7.1 billion of debt, and indebtedness represented 43% 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 unsecured revolving credit facility (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 deepwater Gulf of Mexico development plans. 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 proved undeveloped reserves will depend on our development schedule and plans. A change in future development plans for proved undeveloped reserves 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 the state of Louisiana, 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.

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 will 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 Permian 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 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 2017, 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 2017 – Capital Investment Program.

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.

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 trade, joint venture, and other receivables. We sell our crude oil, natural gas and NGLs to a variety of purchasers. In addition, we are the operator on a majority of our joint venture development projects. As operator of the joint ventures, we pay joint venture expenses and make cash calls on our nonoperating partners for their respective shares of joint venture costs. 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. For example, our partners in the Eastern Mediterranean must obtain financing for their share of significant development expenditures at Leviathan.

In addition, some of our purchasers and joint venture partners are not as creditworthy as we are and may experience credit 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 commodity sales or reimbursement of joint venture costs. Nonperformance by a trade creditor or 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 $1.2 billion in cash and cash equivalents at December 31, 2016 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 trade creditors, 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.

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 may 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 point 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 blowouts, well cratering, fire and explosion and loss of well control which can result in damage to or destruction of wells 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, which can cause loss of or damage to our property.

Our insurance program 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 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 Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Risk and Insurance Program.

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. 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, and the recent change in US Administration has increased uncertainty in these matters.

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.

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

Climate and related energy policy, laws and regulations could change, and substantial uncertainty exists about the nature of many potential developments that could impact the sources and uses of energy. The Paris Agreement, which calls for State parties to establish their own nationally determined contributions (NDCs) for reducing carbon output, entered into force in

November 2016. The previous US Administration's NDC, if not altered, would commit the US to achieve an economy-wide target of reducing its GHG emissions by 26-28% less than the 2005 level by 2025 and to use best efforts to reach a 28% reduction.

There are federal and state responses to climate and energy concerns in the form of laws, regulations and operating guidance, which could alter future demand for our products. Under the previous US Administration, federal agencies in particular pursued a wide variety of climate initiatives.

However, the current US Administration has signaled a change in policy with respect to climate and energy, including potential opposition to the Paris Agreement and the previous administration's Clean Policy Plan.

Domestic and international response to climate and related energy issues are matters of public policy concern. We are currently in a period of increasing uncertainty as to these matters, and, at this time, it is difficult to anticipate how the new US Administration will impact existing laws and regulations, or propose new laws and regulations, and how state governments and other stakeholders may react. As compared with large multi-national, integrated energy companies, we lack the resources or expertise to 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.

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 18. 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
2015			
First Quarter	$ 52.42	$ 41.01	$ 0.18
Second Quarter	53.68	42.13	0.18
Third Quarter	43.03	29.13	0.18
Fourth Quarter	39.85	29.56	0.18
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

On January 24, 2017, our Board of Directors declared a quarterly cash dividend of $0.10 per common share. The dividend will be paid February 21, 2017, to shareholders of record on February 6, 2017. The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

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 January 17, 2017, the number of holders of record of our common stock was 570.

Stock Repurchases The following table summarizes repurchases of our common stock occurring in fourth quarter 2016:

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)
10/1/2016 - 10/31/2016	848	$ 35.78	—	—
11/1/2016 - 11/30/2016	304	35.98	—	—
12/1/2016 - 12/31/2016	391	38.86	—	—
Total	1,543	$ 36.60	—	—

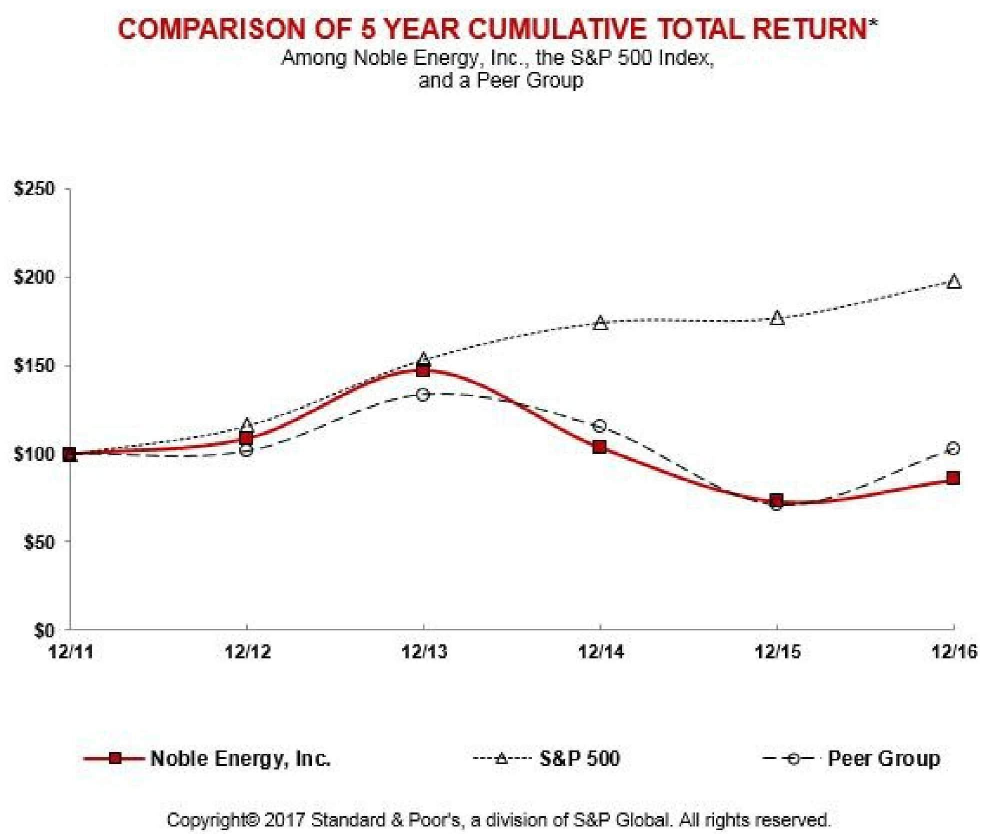
(1) Stock repurchases during the period related to stock received by us from employees for the payment of withholding taxes due on shares of restricted stock issued under our stock-based compensation plans.

Stock Performance Graph This graph shows our cumulative total shareholder return over the five-year period from December 31, 2011 to December 31, 2016. 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 onshore US 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, 2011 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,	2012	2013	2014	2015	2016
Noble Energy, Inc.	$ 108.82	$ 146.99	$ 103.45	$ 73.09	$ 85.47
S&P 500	116.00	153.58	174.60	177.01	198.18
Peer Group	101.34	133.49	114.88	71.07	102.69

Equity Compensation Plan Information The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

Item 6. Selected Financial Data

	Year Ended December 31,				
(millions, except as noted)	2016	2015	2014	2013	2012
Revenues and Income					
Total Revenues	$ 3,491	$ 3,183	$ 5,115	$ 5,015	$ 4,223
(Loss) Income from Continuing Operations Including Noncontrolling Interests	(985)	(2,441)	1,214	907	965
Net (Loss) Income Including Noncontrolling Interests	(985)	(2,441)	1,214	978	1,027
Net (Loss) Income Attributable to Noble Energy	(998)	(2,441)	1,214	978	1027
Per Share Data, Attributable to Noble Energy [1]					
(Loss) Earnings Per Share - Basic					
(Loss) Income from Continuing Operations	$ (2.32)	$ (6.07)	$ 3.36	$ 2.53	$ 2.71
Net (Loss) Income	(2.32)	(6.07)	3.36	2.72	2.89
(Loss) Earnings Per Share - Diluted					
(Loss) Income from Continuing Operations	(2.32)	(6.07)	3.27	2.50	2.68
Net (Loss) Income	(2.32)	(6.07)	3.27	2.69	2.86
Cash Dividends Per Share	0.40	0.72	0.68	0.55	0.45
Year-End Stock Price Per Share	38.06	32.93	47.43	68.11	50.87
Weighted Average Shares Outstanding					
Basic	430	402	361	359	356
Diluted	430	402	367	363	359
Cash Flows					
Net Cash Provided by Operating Activities	$ 1,351	$ 2,062	$ 3,506	$ 2,937	$ 2,933
Additions to Property, Plant and Equipment	1,541	2,979	4,871	3,947	3,650
Proceeds from Divestitures	1,241	151	321	327	1,160
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	299	—	—	—	—
Financial Position					
Cash and Cash Equivalents	$ 1,180	$ 1,028	$ 1,183	$ 1,117	$ 1,387
Property, Plant, and Equipment, Net	18,548	21,300	18,143	15,725	13,551
Goodwill [2]	—	—	620	627	635
Total Assets	21,011	24,196	22,518	19,642	17,554
Long-term Obligations					
Long-Term Debt	7,011	7,976	6,068	4,566	3,736
Deferred Income Taxes	1,819	2,826	2,516	2,441	2,218
Asset Retirement Obligations, Noncurrent	775	861	670	547	333
Other	328	358	417	562	477
Total Equity	9,600	10,370	10,325	9,184	8,258

(1) Amounts adjusted for the 2-for-1 stock split which occurred during second quarter 2013.
(2) Goodwill 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,				
	2016	2015	2014	2013	2012
Operations Information - Consolidated Operations					
Consolidated Crude Oil Sales (MBbl/d)	125	112	103	99	86
Average Realized Price ($/Bbl)	$ 40.39	$ 45.00	$ 91.58	$ 100.29	$ 101.52
Consolidated Natural Gas Sales (MMcf/d)	1,397	1,187	992	901	774
Average Realized Price ($/Mcf)	$ 2.42	$ 2.44	$ 3.38	$ 2.97	$ 2.19
Consolidated NGL Sales (MBbl/d)	54	39	23	16	16
Average Realized Price ($/Bbl)	$ 14.92	$ 13.91	$ 33.75	$ 35.53	$ 35.36
Proved Reserves					
Crude Oil and Condensate Reserves (MMBbls)	333	307	304	322	268
Natural Gas Reserves (Bcf)	5,308	5,549	5,833	5,828	4,964
NGL Reserves (MMBbls)	219	189	128	113	89
Total Reserves (MMBoe)	1,437	1,421	1,404	1,406	1,184
Number of Employees	2,274	2,395	2,735	2,527	2,190

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

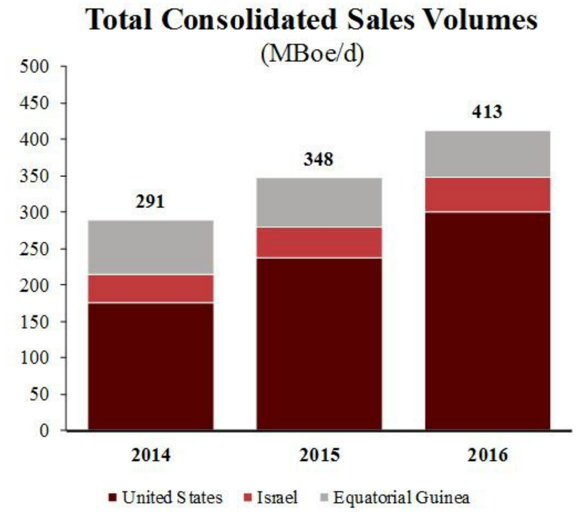
Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide a narrative about our business from the perspective of our management. We use common industry terms, such as thousand barrels of oil equivalent per day (MBoe/d) and million cubic feet equivalent per day (MMcfe/d), to discuss production and sales volumes. Our MD&A is presented in the following major sections:

- Executive Summary;
- Executive Overview;
- Operating Outlook;
- Results of Operations;
- Liquidity and Capital Resources; and
- Critical Accounting Policies and Estimates.

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

EXECUTIVE SUMMARY

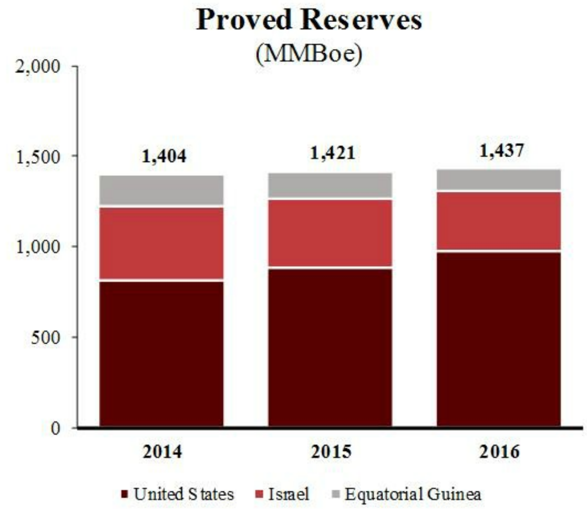
Noble Energy Key Metrics (see links below for further information)



(Excludes sales volumes from equity method investees)

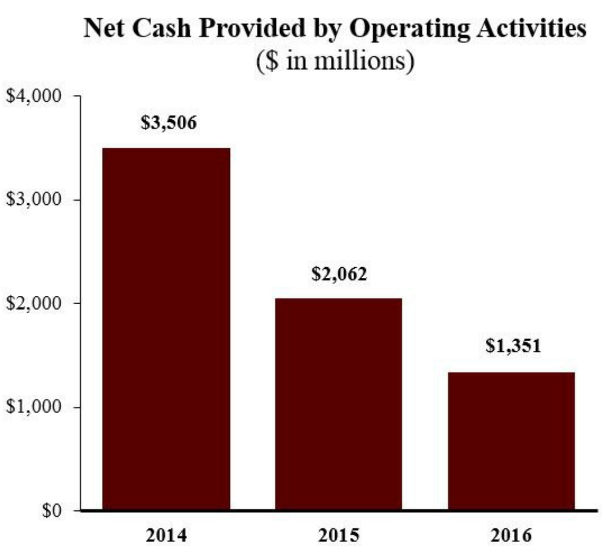
Items 1. and 2. Business and Properties – Sales Volume, Price and Cost Data

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



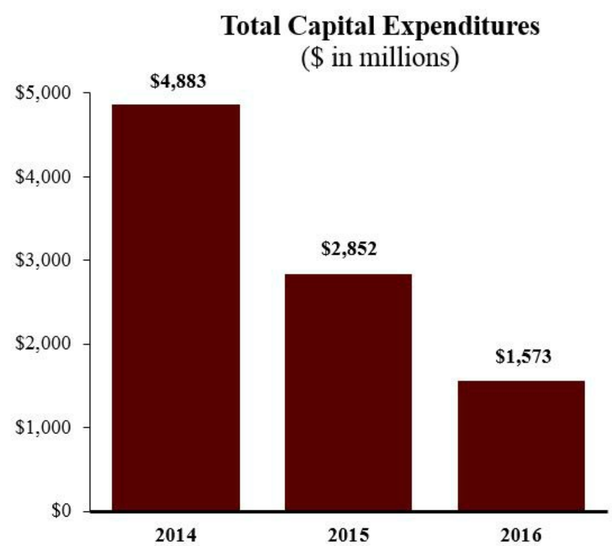
Items 1. and 2. Business and Properties – Proved Reserves Disclosures

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



Liquidity and Capital Resources – Cash Flows

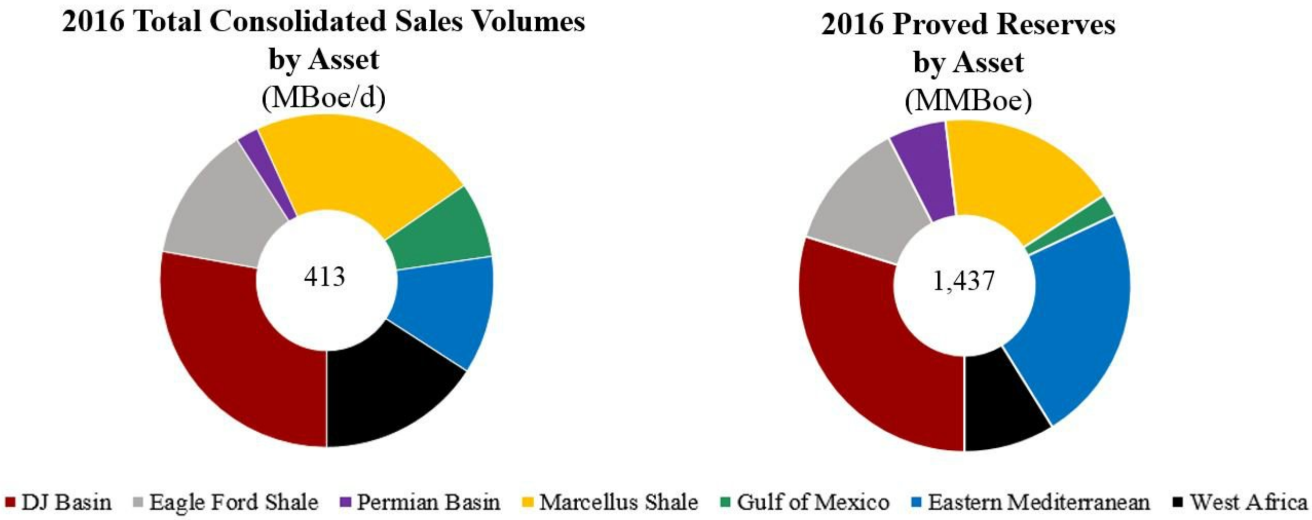
Item 8. Financial Statements and Supplementary Data – Consolidated Statements of Cash Flows



(Excludes Rosetta merger and capital lease obligations)

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

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Acquisition, Capital and Other Exploration Expenditures



(Excludes sales volumes from equity method investees)

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

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

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

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

EXECUTIVE OVERVIEW

Industry Outlook

Crude Oil The oil and gas industry is cyclical, and global crude oil prices are volatile due to three key drivers: OPEC crude oil supply, non-OPEC crude oil supply and global crude oil demand.

The crude oil price downturn that began in 2014 has entered its third year. During 2014, crude oil became oversupplied as production from non-OPEC producers increased, primarily driven by US production growth from tight formations and the de-bottlenecking of transportation infrastructure, while global crude oil demand growth was muted on sub-par global economic growth. This oversupply, coupled with OPEC's decision not to reduce production quotas, resulted in crude oil futures prices falling rapidly in late 2014.

During 2015, prices fell to multi-year lows and the lowest levels since the global 2008 financial crisis. Crude oil prices continued to trade in a lower range during most of 2016 as continued oversupply, and uncertainty surrounding potential OPEC quota reductions, prevented a recovery.

In late 2016, OPEC reached an agreement for a limited, six-month production cut, and, in response, global crude oil prices began to rise. However, OPEC's agreement is contingent on the cooperation of non-OPEC countries, including Russia; therefore, the extent to which these plans will be carried out remains uncertain.

The outlook for 2017 crude oil prices will continue to depend on supply and demand dynamics and global geopolitical and security concerns in crude oil-producing nations. Production levels will be a primary determinant for 2017 as the global crude oil market remains substantially oversupplied. However, it appears that demand has begun to recover in some countries indicating that a sustainable, yet slow, price recovery may have begun.

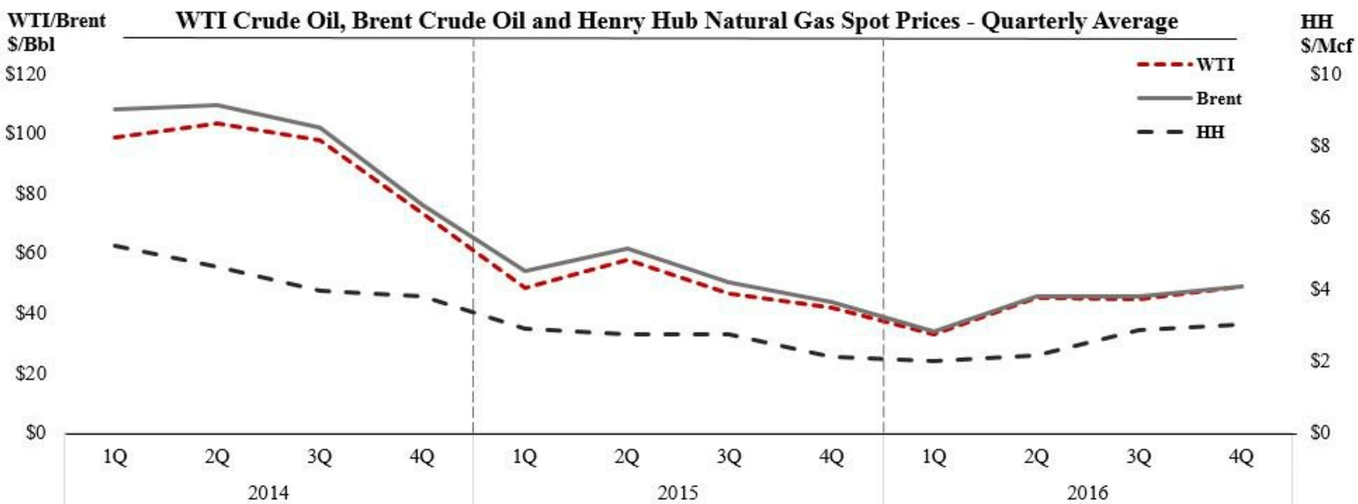
Longer term, we expect supply and demand to continue to re-balance. Recent reductions in industry investment will, over time, reduce production, helping to balance supply and demand in the crude oil market.

Natural Gas The US domestic natural gas market is also oversupplied due to production growth from tight formations. During 2015 and most of 2016, prices remained weak, falling to multi-year lows. In addition, location differentials increased in some regions, resulting in further realized price declines. For a time, domestic production continued to grow, due to drilling efficiency and a backlog of drilled but uncompleted wells in the Marcellus Shale that came online with completion of new pipeline infrastructure, thereby outstripping demand growth.

More recently, however, domestic prices have begun to rebound, primarily in response to slower storage growth, an increase in domestic natural gas consumption, and higher LNG and pipeline exports.

Although the pace of drilling has slowed, it is possible that there may not be more significant improvement in the domestic natural gas supply and demand balance and that oversupply will persist, which could lead to continued price softness in 2017. At a minimum, we expect US natural gas prices to continue to trade in a low range for the near term.

Impact of Current Commodity Prices Although a modest commodity price improvement began in late 2016, our consolidated average realized crude oil price for fiscal year 2016 was 10% lower than for 2015, while our consolidated average natural gas price remained relatively flat as compared with 2015. Over the last two years, lower commodity prices have resulted in a reduction in our capital spending; significantly lower revenues, lower profitability and cash flows; asset and goodwill impairments; and negative (commodity-price driven) reserves revisions. All of these have led to reductions in our stock price in 2015 and 2016. The chart below shows the historical trend in benchmark prices for West Texas Intermediate (WTI) crude oil, Brent crude oil and U.S. Henry Hub natural gas.



Commodity prices continue to be volatile, and the current price improvement trend could stall, or the industry could enter another downturn causing additional material negative impacts on our revenues, profitability, cash flows, liquidity, and reserves, and we could consider further reductions in our capital program or dividends, asset sales or additional organizational changes.

Because the global economic outlook and commodity price environment are uncertain, we have built a liquidity position to ensure financial flexibility. We have also planned a 2017 capital investment program that will be responsive to positive or negative conditions that may develop and support continued investment in a volatile commodity price environment. See 2017 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.*

Potential Cost Inflation Third party oilfield service and supply costs are also subject to supply and demand dynamics. When drilling and development activities slow, in response to extended commodity price declines, third party service and supply costs also tend to decline. During 2016, certain costs declined in response to reduced oilfield activities. However, if the trend toward commodity price improvement continues, and the recovery is robust, we expect demand for oilfield services and supplies to grow, and the costs of drilling, equipping and operating our wells and infrastructure could begin to rise.

Pending Acquisition of Clayton Williams Energy, Inc. On January 13, 2017 we executed a definitive agreement to acquire all of the outstanding common stock of Clayton Williams Energy, Inc. for $2.7 billion in cash and Noble Energy stock. See Items 1. and 2. Business and Properties – *Pending Acquisition of Clayton Williams Energy, Inc.*

Operational Success Despite the negative financial impacts of the low commodity price environment, 2016 was a very successful year operationally and strategically. We directed our focus to the enhancement of onshore US drilling and completions, advancement of Eastern Mediterranean regional natural gas developments, completion of the Gunflint development project in the Gulf of Mexico, start-up of the Alba B3 compression project offshore Equatorial Guinea, initial public offering of our midstream assets, and execution of certain other asset transactions allowing acceleration of asset development.

Just as importantly, we continued to achieve material reductions in capital and controllable unit costs, supporting project returns and margin improvements, and delivered year-over-year volume growth of approximately 19% (or year-over-year organic volume growth of approximately 8% excluding the addition of the Rosetta assets) resulting in record total consolidated sales volumes of 413 MBoe/d (excluding sales volumes from equity investees).

Recent Achievements Our current strategy has enhanced our future outlook and includes:

Portfolio Enhancements, Including:

- integration of Rosetta Resources Inc., which expanded our portfolio with entry into two top-tier US Basins, the Eagle Ford Shale and Permian Basin;
- additional Permian Basin bolt-on acquisitions;
- improvement in the DJ Basin regulatory and legislative environment;
- exchange of acreage in the DJ Basin which increased our contiguous acreage position; and
- dissolution of the Marcellus Shale joint venture, providing increased flexibility and control over our investment.

Operational Accomplishments, Including:

- project sanction readiness at Leviathan;
- increased production with less capital investment;
- improved returns with technology advancements and structural cost savings; and
- delivery of major offshore projects on budget and on schedule.

Financial Strength, Including:

- proactive and strategic action to manage within cash flows;
- strong liquidity position including cash on hand and unused borrowing capacity;
- portfolio management and midstream strategy, which increase our future financial capacity;
- reduction of our outstanding debt through cash on hand; and
- maintenance of our investment grade credit rating.

In summary, during 2016 we maintained our operational momentum, investment flexibility, and strong financial liquidity which we expect to carry over to 2017.

2016 Successes More specifically, our 2016 successes included the following:

Onshore US Growth Onshore, we continued our excellent safety performance while increasing our development activity in the DJ Basin, Eagle Ford Shale and Permian Basin. We expanded our Permian Basin position with an acreage acquisition and further enhanced our Colorado Wells Ranch position through an acreage exchange.

In October, we entered into a definitive agreement to separate our Marcellus Shale 50-50 Joint Venture, providing for greater control and flexibility over our future pace of development.

Production Volume Increases Efficiencies generated by drilling time reductions and completion improvements resulted in increased production as we delivered year-over-year volume growth of approximately 19% resulting in record total consolidated average sales volumes of 413 MBoe/d.

Capital Cost Reductions While delivering higher production volumes, we realized significant reductions in capital expenditures, over 45% from 2015, excluding the impact of the Rosetta Merger.

Lease Operating and G&A Expense Reductions We continued to realize significant reductions in unit costs for lease operating and general and administrative (G&A) expenses, 19% and 15%, respectively, on a BOE basis from 2015.

Major Project Successes Offshore, our major project execution capabilities enabled start up at our new Gunflint project in the Gulf of Mexico in July. Offshore Israel, the establishment of the Natural Gas Framework by the Government of Israel and execution of additional long-term natural gas sales agreements positioned us for sanction of our next major offshore development project, Leviathan. And offshore Equatorial Guinea, the Alba B3 compression platform was successfully installed, on schedule and within budget, and commenced production, extending the resource recovery life and slowing the natural decline of the Alba field. Our operated projects in the Eastern Mediterranean and West Africa continue to provide a source of reliable production and cash flows.

Liquidity Enhancements While accelerating our onshore US program, we ensured liquidity and enhanced our financial flexibility by generating over $1.5 billion of proceeds from property divestments and the initial public offering of Noble Midstream Partners common units. We used new Term Loan Facility proceeds to repurchase higher cost public debt, and, more recently were able to repay $850 million of the Term Loan Facility borrowings.

2016 Financial Results Our financial results included:

- crude oil, natural gas and NGL revenues of $3.4 billion, as compared with $3.1 billion for 2015;
- net loss attributable to Noble Energy of $998 million, as compared with net loss of $2.4 billion for 2015;
- net loss on commodity derivative instruments of $139 million (including $708 million non-cash loss), as compared with $501 million net gain (including $508 million non-cash loss) for 2015;
- dry hole expense of $579 million, as compared with $266 million for 2015;
- undeveloped leasehold impairment expense of $93 million, as compared with $21 million for 2015;

- reduced lease operating expense of $3.59 per BOE, as compared with $4.43 per BOE for 2015, a reduction of 19%;
- reduced general and administrative expense of $2.64 per BOE, as compared with $3.11 per BOE for 2015, a reduction of 15%;
- asset impairment expense of $92 million, as compared with $533 million for 2015;
- diluted loss per share attributable to Noble Energy of $2.32, as compared with diluted loss per share of $6.07 for 2015;
- cash flows provided by operating activities of $1.4 billion, as compared with $2.1 billion in 2015; and
- capital expenditures of $1.6 billion, as compared with $2.9 billion, excluding the Rosetta Merger, in 2015.

Significant Events Impacting Liquidity Included:

- net cash proceeds of $299 million received from issuance of Noble Midstream Partners common units, net of offering costs;
- proceeds of $1.2 billion from asset sales; and
- prepayment of $850 million of borrowings under our Term Loan Facility.

Year-end Financial Metrics Included:

- cash balance of $1.2 billion, as compared with $1.0 billion at December 31, 2015;
- total liquidity of $5.2 billion, as compared with $5.0 billion at December 31, 2015; and
- ratio of debt-to-book capital of 43%, as compared with 43% at December 31, 2015.

See Results of Operations and Liquidity and Capital Resources, below.

Sales Volumes On a BOE basis, total consolidated sales volumes were 19% higher for 2016 as compared with 2015, and our mix of sales volumes was 43% global liquids, 36% US natural gas and 21% international natural gas. See Results of Operations – Revenues, below.

Cost Reduction Efforts During 2016, we continued to focus on maintaining our strong safety culture, driving operational efficiencies and reducing our cost structure. Continued cost reduction initiatives, including both operational enhancements and new pricing arrangements with suppliers, enabled us to reduce unit costs in lease operating expense and general and administrative expense as compared with 2015. Our global portfolio provides significant optionality, allowing us to adjust spending in response to the commodity price environment. Capital spending reductions, coupled with cost reduction activities, have aligned overall cash expenditures more closely with operating cash flows in the lower commodity price environment. Over the last two years, we also implemented organizational changes including a workforce reduction.

Acquisitions and Divestitures During 2016, we engaged in various acquisition and divestiture activity. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions, Divestitures and Merger.

OPERATING OUTLOOK

Positioned for the Future We believe the following factors will contribute to the sustainability of our business throughout the commodity price cycle, including extended periods of lower prices:

- we have a high-quality, globally diversified portfolio of assets, focused on top-tier basins, and the majority of our assets are held by production, which provides investment optionality and flexibility;
- we have exploration expertise which has led to numerous discoveries, in the deepwater Gulf of Mexico, Levant Basin offshore Eastern Mediterranean and the Douala Basin offshore West Africa, resulting in major development project opportunities;
- we have operational and technical expertise which has led to our delivery of major development projects on schedule and within budget providing a competitive and financial advantage in our industry;
- we have achieved substantial cost reductions (and are well-positioned on the global cost supply curve) impacting both operating expenses and capital expenditures;
- we have designed a capital investment program, with flexibility allowing us to respond to changing commodity price conditions in 2017;
- we have adjusted our quarterly dividend to 10 cents per common share; and
- we have robust liquidity of $5.2 billion at December 31, 2016 and ability to access capital markets.

See also Results of Operations and Liquidity and Capital Resources, below.

As we enter 2017, we believe we have positioned the Company for sustainability, operational efficiency, and long-term success throughout the oil and gas business cycle. However, if the industry downturn continues for an extended period, or becomes more severe, we could experience additional material negative impacts on our revenues, profitability, cash flows, liquidity and proved reserves, and in response, we may consider further reductions in our capital program or dividends, asset sales or additional organizational changes. Our production and our stock price could decline further 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.*

2017 Production We continue our comprehensive effort to spend within cash flow, manage the Company's balance sheet and position ourselves for future growth. To this end, we have adopted a 2017 capital program closely aligned with expected cash flow. Therefore, our total crude oil, natural gas and NGL production for 2017 may not grow at a rate consistent with prior years. 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;
- Israeli industrial and residential demand for electricity, which is largely impacted by weather conditions and conversion of Israeli electricity portfolio from coal to natural gas;
- timing of the divestiture of the remaining 7.5% working interest in the Tamar field which will lower our sales volumes;
- potential growth in the Israeli natural gas export market;
- timing of crude oil and condensate liftings impacting sales volumes in West Africa;
- natural field decline in onshore US, deepwater Gulf of Mexico and offshore Equatorial Guinea;
- potential weather-related volume curtailments due to hurricanes in the deepwater Gulf of Mexico and Gulf Coast areas, or winter storms and flooding impacting onshore US operations;
- reliability of support equipment and facilities, pipeline disruptions, and/or potential pipeline and processing facility capacity constraints which may cause restrictions or interruptions in production and/or midstream processing;
- malfunctions and/or mechanical failures at terminals or other onshore US delivery points;
- impact of enhanced completion efforts for onshore US assets;
- potential shut-in of US producing properties if storage capacity becomes unavailable;
- potential drilling and/or completion permit delays due to future regulatory changes; and
- potential purchases of producing properties or divestments of operating assets.

2017 Capital Investment Program Given the current commodity price environment, we have designed a flexible capital investment program as part of our comprehensive effort to spend within cash flows and manage the Company's balance sheet.

Our preliminary 2017 capital investment program will accommodate an investment level of approximately $2.3 to $2.6 billion. Approximately 75% of the total capital program is allocated to US onshore development, primarily focused on liquids-rich opportunities in the DJ Basin, Delaware Basin, and Eagle Ford Shale. Eastern Mediterranean capital expenditures, including initial development costs associated with the Leviathan project, represent over 20% of the total.

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 and the ability to achieve material supplier price reductions;
- production, drilling, delivery commitments or other contractual obligations;
- drilling results;
- property acquisitions and divestitures;
- exploration activity;
- cash flows from operations;
- indebtedness levels;
- availability of financing or other sources of funding;
- permitting activity in the deepwater Gulf of Mexico;
- potential legislative or regulatory changes regarding the use of hydraulic fracturing;
- potential changes in the fiscal regimes of the US and other countries in which we operate; and
- impact of new laws and regulations on our business practices.

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 – Financing Activities, and – Contractual Obligations – Exploration Commitments and Continuous Development Obligations.

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

Exploration Activities As we develop our near-term inventory, we will consider expanding the portfolio to include additional long-term and/or large-scale exploration opportunities. In this regard, we continue to conduct exploration activities in various geographical areas and have capitalized a significant amount of exploratory drilling costs. In the event we conclude that an exploratory well did not encounter hydrocarbons or that a discovery or prospect is not economically or operationally viable, the associated capitalized exploratory well costs would be charged to expense. For example, in 2016, we recorded impairments or dry hole expense totaling $579 million primarily associated with exploration activities in the deepwater Gulf of Mexico, offshore Israel and offshore West Africa.

We are currently evaluating development scenarios and assessing plans to progress appraisal at our Katmai discovery, deepwater Gulf of Mexico. We currently have capitalized costs of approximately $150 million for Katmai.

In addition, we have a potential commitment to drill an exploration well offshore Suriname, pending seismic survey evaluation.

We may also relinquish certain undeveloped leases prior to expiration, based upon geological evaluation or other factors. For example, in 2016, we wrote off $58 million of cost related to deepwater Gulf of Mexico undeveloped leases and $25 million for Falkland Islands licenses.

We have numerous leases for deepwater Gulf of Mexico prospects that have not yet been drilled. A significant portion of these leases are scheduled to expire over the years 2018 to 2020 and some leases may become impaired if production is not established, we do not take action to extend the terms of the leases, or the leases become uneconomic due to low commodity prices or other factors.

At December 31, 2016, we have capitalized costs related to exploratory wells of $768 million. We also have capitalized undeveloped leasehold cost of approximately $105 million related to deepwater Gulf of Mexico. As a result of our exploration activities, future exploration expense, including undeveloped leasehold amortization and impairment expense, could be significant.

See Item 1A. Risk Factors, Results of Operations – Operating Costs and Expenses – Oil and Gas Exploration Expense, and Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Development Concept Selection Costs

When we discover significant resources, such as our Leviathan and Cyprus discoveries in the Eastern Mediterranean, full field development may require several phases, with various facilities serving both domestic and regional export demand. In order to determine an optimum development concept for these discoveries, we and our partners engage in development planning, also known as pre-FEED and FEED studies. Furthermore, we may progress pre-FEED and FEED studies simultaneously for multiple development concepts, with the realization that only one concept may ultimately be approved or be economically feasible. This simultaneous progression of multiple concepts enables us to advance a final investment decision and quality development of resources in a timely and efficient manner.

Conducting pre-FEED and FEED work to varying degrees for a range of phased development concepts may result in our incurring significant charges, as compared with pre-FEED and FEED costs incurred for previous offshore projects where the resources were not as significant. Other factors that may increase our pre-FEED and FEED costs include location of a field in a remote and/or under-developed area, lack of availability of, or capacity at, third party production platforms or other infrastructure, technical complexity, market availability, and significant time and effort required for government approval. While a development project may not be formally sanctioned, such as our Leviathan discovery, once a final development concept has been determined, we expect to identify certain concepts that must be eliminated from further consideration, and their associated costs written off. In fourth quarter 2016, we selected the initial development concept for the first phase of the Leviathan development project and wrote off $88 million associated with concepts that were not selected. See Items 1. and 2. Business and Properties – International – Eastern Mediterranean (Israel and Cyprus).

Producing Properties

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

In addition, in certain onshore US areas, transportation bottlenecks caused by oversupply and/or lack of infrastructure can reduce the amount of production reaching premium markets, resulting in higher basis differentials, or differences between WTI and HH pricing and the average prices we actually receive. An increase in these basis differentials could also reduce cash flows and result in property impairment charges.

The cash flow model that we use to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future crude oil and natural gas production along with operating and development costs, and the market outlook on forward commodity prices. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward commodity prices, or increases in basis differentials, alone could result in an impairment.

In addition, well decommissioning programs, especially in deepwater or remote locations are often complex and expensive and may require several phases over a multi-year period, such as the current decommissioning activities occurring at the MacCulloch field in the North Sea. It may be difficult to estimate timing of actual abandonment activities, which are subject to regulatory approval, and the availability of rigs and services. It may be difficult to estimate costs as rigs and services become more expensive in periods of higher demand and less expensive in periods of low demand. Furthermore, regulations for decommissioning activities are under constant review for amendment and expansion and more stringent requirements are frequently mandated. Therefore, our asset retirement obligation (ARO) estimates may change, sometimes significantly, and could result in asset impairment. See Items 1. and 2. Business and Properties.

Climate Change Climate change has become the subject of significant global focus. The impact of human activity on the climate remains a complex issue. Numerous governments around the world have concluded that it poses an urgent threat that requires the reduction of greenhouse gas emissions and other governments are responding with similar policies.

Crude oil and natural gas exploration and production operations are a direct source of certain GHGs, namely carbon dioxide and methane, and an indirect source of GHGs from the combustion of crude oil and natural gas products. Future restrictions on the production, use, emission or combustion of hydrocarbons could have a significant impact on our operations. We therefore are actively monitoring the following climate change related issues:

Impact of Legislation and Regulation Among the commercial risks associated with the exploration and production of hydrocarbons is the uncertainty of government-imposed climate change obligations, including cap and trade schemes, carbon taxes, and other controls that may affect us, our suppliers, and our customers. The cost of meeting these requirements may have an adverse impact on our financial condition, results of operations and cash flows, and could reduce the demand for our products.

In June 2013, President Obama unveiled a Presidential climate action plan designed to reduce carbon emissions in the US, prepare the US for potential climate change impacts, and lead international efforts to address potential global climate change. In furtherance of that plan, the Obama Administration launched a number of initiatives, including the development of standards to increase vehicle fuel economy and a Strategy to Reduce Methane Emissions from the oil and gas industry. See also Items 1. and 2. Business and Properties - Regulations. It is not yet clear how the current US Administration and Congress will impact these initiatives.

Impact of International Accords The Kyoto Protocol (Protocol) to the United Nations Framework Convention on Climate Change (Convention) went into effect in February 2005 and required all industrialized nations that ratified the Protocol to reduce or limit GHG emissions to a specified level by 2012. Certain parties then agreed to a second commitment period of the Kyoto Protocol which will last until December 31, 2020. Although a party to the Convention, the US did not ratify the Protocol.

Continuing international negotiations resulted in more than 190 countries, including the US, signing a new climate change agreement in Paris in 2015. The Paris Agreement aims to limit any increase in global temperature to less than 2°C greater than pre-industrial levels and to pursue efforts to limit the increase to 1.5°C. Parties are to submit their own nationally determined contributions (NDCs) toward GHG emissions reductions, which, unlike the reductions in the Protocol, will not be binding obligations. To help developing countries address climate change, moreover, the Paris Agreement sets a floor of $100 billion in annual aid collectively from developed countries. A new mitigation mechanism also will be developed over the next several years. The Paris Agreement entered into force in November 2016, thirty days after the required ratification by at least 55 countries that produce at least 55% of the world's GHGs. That same month, at the 22nd Conference of the Parties to the Convention (COP 22), State Parties to the Agreement collaborated on efforts focused on implementation of the Agreement. The previous US Administration's NDC sets an economy-wide target by 2025 of reducing GHG emissions by 26-28% as compared to 2005 levels, and to make best efforts to reach 28%. The US presidential climate action plan discussed above reportedly is expected to account for much, but not all, of the reduction. This may change in the future with the current US Administration.

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 or regulations.

Indirect Consequences of Regulation or Business Trends We believe there are both risks and opportunities arising from the global climate change initiatives. In terms of opportunities, the regulation of GHGs and introduction of formal technology incentives, such as enhanced oil recovery, carbon sequestration and low carbon fuel standards, could benefit us in a variety of ways.

First, sales of natural gas comprised approximately 57% of our 2016 total sales volumes. The burning of natural gas produces lower levels of GHG emissions as compared to fuels such as liquid hydrocarbons and coal. In addition, public concern about nuclear safety has increased. These factors could increase the demand for natural gas as fuel for power generation. Also, should renewable resources, such as wind or solar power, become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply.

Further, future GHG standards for vehicles could result in the use of natural gas as transportation fuel. This may also increase the market demand for natural gas.

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.

RESULTS OF OPERATIONS

Selected financial information is as follows:

	Year Ended December 31,		
	2016	2015	2014
(millions, except per share)			
Total Revenues	$ 3,491	$ 3,183	$ 5,115
Total Operating Expenses	4,787	5,655	4,197
Operating (Loss) Income	(1,296)	(2,472)	918
Total Other (Income) Expense	476	(253)	(792)
(Loss) Income from Operations Before Income Taxes	(1,772)	(2,219)	1,710
Net (Loss) Income Including Noncontrolling Interests	(985)	(2,441)	1,214
Less: Net Income Attributable to Noncontrolling Interests	13	—	—
Net (Loss) Income Attributable to Noble Energy	(998)	(2,441)	1,214
Net (Loss) Income Attributable to Noble Energy Per Share			
Basic	(2.32)	(6.07)	3.36
Diluted	(2.32)	(6.07)	3.27

See following discussion for explanation of year-to-year changes.

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.

Historically, we recorded revenue at the net price we received from the purchaser, net of transportation, fractionation or processing costs. Beginning in 2016, we changed our presentation of revenue to no longer include expenses netted from revenue by the purchaser. Crude oil, natural gas and NGL sales are now shown without deductions relating to transportation, fractionation or processing. These deductions are now recorded as production expense. Prior year amounts, including revenues, expenses, average realized sales prices and average production costs per BOE, have been reclassified to conform to the current presentation. For NGL sales, amounts reclassified for 2015 and 2014 totaled $50 million and $14 million, respectively. Amounts reclassified for crude oil and natural gas sales were de minimis.

In addition, commodity prices we receive may be reduced by location basis differentials, which can be significant. For example, transportation bottlenecks and oversupply in the Marcellus Shale have reduced the amount of production reaching higher priced out-of-basin locations. As a result of location basis differentials, our reported sales prices may differ significantly from published commodity price benchmarks for the same period.

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)	Natural Gas (MMcf/d)	NGLs (MBbl/d)	Total (MBoe/d) [1]	Crude Oil & Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)
Year Ended December 31, 2016							
United States	99	881	54	301	$ 39.59	$ 2.11	$ 14.92
Israel	—	281	—	47	—	5.21	—
Equatorial Guinea [2]	26	235	—	65	43.54	0.27	—
Total Consolidated Operations	125	1,397	54	413	40.39	2.42	14.92
Equity Investee [3]	2	—	5	7	45.44	—	26.30
Total	127	1,397	59	420	$ 40.46	$ 2.42	$ 15.96
Year Ended December 31, 2015							
United States	81	708	39	237	$ 43.46	$ 2.10	$ 13.91
Israel	—	252	—	42	—	5.34	—
Equatorial Guinea [2]	31	227	—	69	48.85	0.27	—
Total Consolidated Operations	112	1,187	39	348	45.00	2.44	13.91
Equity Investee [3]	2	—	5	7	48.85	—	28.40
Total	114	1,187	44	355	$ 45.05	$ 2.44	$ 15.59
Year Ended December 31, 2014							
United States	68	518	23	176	$ 89.60	$ 3.86	$ 33.75
Israel	—	231	—	39	—	5.57	—
Equatorial Guinea [2]	33	243	—	74	94.61	0.27	—
China	2	—	—	2	103.74	—	—
Total Consolidated Operations	103	992	23	291	91.58	3.38	33.75
Equity Investee [3]	2	—	5	7	96.53	—	62.89
Total	105	992	28	298	$ 91.65	$ 3.38	$ 39.19

(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 the Alba plant in Equatorial Guinea.

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

	Crude Oil & Condensate	Natural Gas	NGLs	Total
(millions)				
2014 Sales Revenues	$ 3,438	$ 1,223	$ 284	$ 4,945
Changes due to				
Increase in Sales Volumes	306	241	181	728
Decrease in Sales Prices	(1,904)	(408)	(268)	(2,580)
2015 Sales Revenues	$ 1,840	$ 1,056	$ 197	$ 3,093
Changes due to				
Increase in Sales Volumes	153	190	84	427
Increase (Decrease) in Sales Prices	(139)	(7)	15	(131)
2016 Sales Revenues	$ 1,854	$ 1,239	$ 296	$ 3,389

Crude Oil and Condensate Sales Revenues 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 Permian Basin primarily attributable to full year consolidation following the Rosetta Merger;
- sales volumes from the Big Bend and Dantzler developments (deepwater Gulf of Mexico), which began producing fourth quarter 2015 and contributed 12 MBbl/d, net, collectively in 2016; and
- start up of the deepwater Gulf of Mexico Gunflint development in July 2016 which contributed 3 MBbl/d;

partially offset by:

- a 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 Aseng and Alen, offshore Equatorial Guinea.

Revenues from crude oil and condensate sales decreased by $1.6 billion, or 46%, in 2015 as compared with 2014 due to the following:

- a 51% 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 in 2015;
- decrease in sales volumes due to planned downtime and maintenance as well as natural field decline in the deepwater Gulf of Mexico and the Aseng field, offshore Equatorial Guinea; and
- decrease in sales volumes due to the sale of our China assets at the end of second quarter 2014;

partially offset by:

- higher sales volumes of 7 MBbl/d in the DJ Basin primarily attributable to increased well productivity due to enhanced completion techniques and increased processing capacity;
- sales volumes of 7 MBbl/d contributed by our recently-acquired Eagle Ford Shale and Permian Basin assets; and
- start up of the deepwater Gulf of Mexico Rio Grande development in fourth quarter 2015 which contributed 2 MBbl/d.

Natural Gas Sales Revenues Revenues from natural gas sales increased by $183 million, or 17%, in 2016 as compared with 2015. Although consolidated average realized prices remained flat, sales volume increases were 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 Permian 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.

Revenues from natural gas sales decreased by $167 million, or 14%, in 2015 as compared with 2014 due to the following:

- a 28% decrease in total consolidated average realized natural gas prices, including a 46% decrease in US average realized prices primarily due to oversupply; and

- a widening of location basis differentials in the Marcellus Shale due to an oversupply of natural gas in the region which lowered the price we received;

partially offset by:

- higher sales volumes of 28 MMcf/d in the DJ Basin primarily attributable to increased well productivity due to enhanced completion techniques and increased processing capacity;
- higher sales volumes of 131 MMcf/d in the Marcellus Shale primarily attributable to well completion and infrastructure development;
- sales volumes of 58 MMcf/d contributed by our recently-acquired Eagle Ford Shale and Permian Basin assets; and
- record sales volumes from the Tamar field, offshore Israel, which contributed an incremental 21 MMcf/d, in response to higher power generation needs.

NGL Sales Revenues Revenues from NGL sales increased by $99 million, or 50%, in 2016 as compared with 2015 due to the following:

- higher sales volumes of 14 MBbl/d in the Eagle Ford Shale and Permian Basin primarily attributable to a full year of production as well as increased development activity;
- a 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.

Revenues from NGL sales decreased by $87 million, or 31%, during 2015 as compared with 2014 due to the following:

- a 59% decrease in total consolidated average realized NGL prices, which are closely linked to the NYMEX WTI crude oil price decline, particularly in the Marcellus Shale;

partially offset by:

- 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;
- higher sales volumes of 5 MBbl/d in the Marcellus Shale primarily attributable to well completion and infrastructure development; and
- sales volumes of 9 MBbl/d contributed by our recently-acquired Eagle Ford Shale and Permian Basin assets.

Income from Equity Method Investees We have interests in various equity method investees that operate midstream assets onshore US and West Africa. Equity method investments are included in other noncurrent assets in our consolidated balance sheets, and our share of earnings is reported as income from equity method investees in our consolidated statements of operations. Within our consolidated statements of cash flows, activity is reflected within cash flows provided by operating activities and cash flows provided by (used in) investing activities.

Our share of operations of equity method investees was as follows:

	Year Ended December 31,		
	2016	2015	2014
Net Income (in millions)			
CONE Gathering and CONE Midstream	$ 48	$ 46	$ 9
AMPCO and Affiliates	16	8	62
Alba Plant	34	31	99
Other	4	5	—
Dividends (in millions)			
CONE Gathering and CONE Midstream	27	17	48
AMPCO and Affiliates	16	31	61
Alba Plant	40	29	117
Sales Volumes			
Methanol (MMgal)	162	117	130
Condensate (MBbl/d)	2	2	2
LPG (MBbl/d)	5	5	5
Average Realized Prices			
Methanol (per gallon)	$ 0.63	$ 0.92	$ 1.26
Condensate (per Bbl)	45.44	48.85	96.53
LPG (per Bbl)	26.30	28.40	62.89

CONE Gathering and CONE Midstream In 2014, our jointly-owned equity method investee, CONE Gathering, contributed a significant majority of its existing assets to a newly-formed master limited partnership, CONE Midstream, concurrently with an initial public offering of limited partner units. CONE Gathering subsequently distributed $204 million of cash to us.

During fourth quarter 2016, CONE Gathering contributed its remaining 25% ownership interest in CONE Midstream DevCo I LP to CONE Midstream for a total valuation of $248 million. Upon closing, we received $70 million in cash and approximately 2.6 million CNNX limited partnership units.

AMPCO and Affiliates Net income from AMPCO and affiliates increased in 2016 as compared with 2015 primarily due to higher methanol sales volumes offset by lower methanol prices.

Net income from AMPCO and affiliates decreased in 2015 as compared with 2014 primarily due to lower average realized methanol prices resulting from lower global demand and expenses associated with plant turnaround activities conducted first quarter 2015.

Alba Plant Net income from Alba Plant remained flat in 2016 as compared to 2015.

Net income from Alba Plant in 2015 decreased as compared to 2014 primarily due to the decrease in the average realized sales prices of condensate and LPG resulting from lower global demand.

Operating Costs and Expenses

Operating costs and expenses were as follows:

(millions)	2016	Inc (Dec) from Prior Year	2015	Inc (Dec) from Prior Year	2014
Production Expense	$ 1,083	11 %	$ 979	4 %	$ 945
Exploration Expense	925	90 %	488	(2)%	498
Depreciation, Depletion and Amortization	2,454	15 %	2,131	21 %	1,759
General and Administrative	399	1 %	396	(21)%	503
Asset Impairments	92	(83)%	533	7 %	500
Goodwill Impairment	—	N/M	779	N/M	—
Other Operating (Income) Expense, Net	(166)	N/M	349	N/M	(8)
Total	$ 4,787	(15)%	$ 5,655	35 %	4,197

N/M amount is not meaningful.

Changes in operating costs and expenses are discussed below.

Production Expense Components of production expense were as follows:

(millions, except unit rate)	Total per BOE [1]	Total	United States	Israel	Equatorial Guinea	Other Int'l/ Corporate [2]
Year Ended December 31, 2016						
Lease Operating Expense [3]	$ 3.59	$ 542	$ 400	$ 37	$ 105	$ —
Production and Ad Valorem Taxes	0.52	78	78	—	—	—
Transportation and Gathering Expense	3.07	463	463	—	—	—
Total Production Expense	$ 7.18	$ 1,083	$ 941	$ 37	$ 105	$ —
Total Production Expense per BOE		$ 7.18	$ 8.56	$ 2.14	$ 4.42	N/M
Year Ended December 31, 2015						
Lease Operating Expense [3]	$ 4.43	$ 563	$ 370	$ 49	$ 131	$ 13
Production and Ad Valorem Taxes	1.00	127	125	—	—	2
Transportation and Gathering Expense	2.26	289	289	—	—	—
Total Production Expense	$ 7.69	$ 979	$ 784	$ 49	$ 131	$ 15
Total Production Expense per BOE		$ 7.69	$ 9.07	$ 3.15	$ 5.21	N/M
Year Ended December 31, 2014						
Lease Operating Expense [3]	$ 5.58	$ 593	$ 343	$ 54	$ 147	$ 49
Production and Ad Valorem Taxes	1.73	184	166	—	—	18
Transportation and Gathering Expense	1.60	168	166	—	—	2
Total Production Expense	$ 8.91	$ 945	$ 675	$ 54	$ 147	$ 69
Total Production Expense per BOE		$ 8.91	$ 10.55	$ 3.84	$ 5.44	N/M

N/M Amount is not meaningful.

(1) Consolidated unit rates exclude sales volumes and expenses attributable to equity method investees and include expenses related to Noble Midstream Partners.

(2) Other International, Corporate includes the North Sea (in 2014 and 2015), China (through June 30, 2014) and corporate expenditures.

(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 decreased in 2016 as compared with 2015 due to the following:

- decrease of $92 million onshore US, 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 onshore US and deepwater Gulf of Mexico development activities; and
- increase of $38 million related to the acquisition of Eagle Ford Shale and Permian Basin production third quarter 2015.

Lease operating expense decreased in 2015 as compared with 2014 due to the following:

- decrease of $17 million from sales of non-strategic onshore US properties in 2014;
- decrease of $17 million due to the sale of our China assets at the end of second quarter 2014;
- decrease of $15 million in deepwater Gulf of Mexico due to cessation of operations at South Raton, natural field decline and cost reduction initiatives;
- decrease of $15 million offshore West Africa due to cost reduction initiatives and lower production;
- decrease of $6 million in offshore Israel due to cost reduction initiatives; and
- decrease of $9 million in other international/corporate due to cost reduction initiatives;

partially offset by:

- increase of $38 million attributable to our recently-acquired Eagle Ford Shale and Permian Basin assets; and
- increase of $11 million in the Marcellus Shale due to increased production.

Production and Ad Valorem Tax Expense

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

Production and ad valorem taxes decreased in 2015 as compared with 2014, primarily driven by lower revenues resulting from the decline in commodity prices in the US as well as a reduction of $17 million resulting from the sale of our China assets at the end of the second quarter 2014.

Transportation Expense

Transportation 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 our new deepwater Gulf of Mexico projects at Big Bend and Dantzler (which began producing fourth quarter 2015) and Gunflint (which began producing in July 2016).

Transportation expense increased in 2015 as compared with 2014 due to:

- increase of $81 million in the Marcellus Shale due to higher production and increased expenses due to service contracts with CONE Gathering;
- increase of $33 million due to recently-acquired Eagle Ford Shale and Permian Basin properties; and
- increase of $12 million in the DJ Basin due to the May 2015 commencement of Tallgrass pipeline, which transports DJ Basin crude oil;

partially offset by:

- $8 million decrease due to the sale of non-strategic onshore US, China and North Sea properties in 2014.

Unit Rate Per BOE While total production expense increased as a result of higher production for 2016 as compared with 2015, costs on a per BOE basis declined. The decline on a per unit basis is driven primarily by lower production and ad valorem taxes as a result of the current commodity price environment and lower lease operating expenses as we continue to strive for 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 onshore US assets.

The unit rate of total production expense per BOE decreased for 2015 as compared with 2014 primarily due to lower production and ad valorem taxes as a result of the commodity price environment in addition to cost reduction initiatives in lease operating expense and higher production volumes.

Exploration Expense Components of exploration expense were as follows:

(millions)	Total	United States	Eastern Mediterranean [1]	West Africa [2]	Other Int'l, Corporate [3]
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	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
Year Ended December 31, 2014					
Leasehold Impairment and Amortization	$ 43	$ 43	$ —	$ —	$ —
Dry Hole Cost	226	147	—	—	79
Seismic, Geological and Geophysical	86	28	4	18	36
Staff Expense	72	25	2	4	41
Other [5]	71	25	11	4	31
Total Exploration Expense	$ 498	$ 268	$ 17	$ 26	$ 187

(1) Eastern Mediterranean includes Israel and Cyprus.

(2) West Africa includes Equatorial Guinea, Cameroon and Gabon.
(3) Other International, Corporate includes the Falkland Islands, Suriname and other new ventures and corporate expenditures.
(4) For a discussion of 2016 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.
(5) Includes lease rental and other exploration expense.

Exploration expense for 2016 included:

- leasehold impairment expense including the write-off of leases and licenses of $58 million for the deepwater Gulf of Mexico, $25 million for the Falkland Islands and $10 million for other onshore US;
- dry hole cost including costs related to the Silvergate exploratory well, deepwater Gulf of Mexico, the Dolphin 1 natural gas discovery, offshore Israel, and certain discoveries offshore West Africa;
- seismic expense relating to the acquisition of 3D seismic data in West Africa and other international areas;
- other cost for onshore US including lease rentals primarily related to Permian Basin leases; and
- salaries and related expenses for corporate exploration and new ventures personnel.

Oil and gas exploration expense decreased in 2015 as compared with 2014. Expense for 2015 includes the following:

- 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;
- West Africa dry hole cost including the Cheetah well (offshore Cameroon) and Other International dry hole cost including the Humpback well (offshore Falkland Islands), neither of which identified commercial quantities of hydrocarbons; and
- salaries and related expenses for corporate exploration and new ventures personnel.

Exploration expense included stock-based compensation expense of $10 million in 2016, $13 million in 2015 and $17 million in 2014.

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

	Year Ended December 31,		
(millions, except unit rate)	2016	2015	2014
United States	$ 2,122	$ 1,692	$ 1,318
Israel	81	70	63
Equatorial Guinea	205	326	299
Other International, and Corporate	46	43	79
Total DD&A Expense (1)	$ 2,454	$ 2,131	$ 1,759
Unit Rate per BOE (2)	$ 16.26	$ 16.75	$ 16.55

(1) DD&A expense includes accretion of discount on asset retirement obligations of $48 million in 2016, $43 million in 2015, and $36 million in 2014.
(2) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.

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 deepwater Gulf of Mexico in 2016 and 2015;
- increase of $134 million related to the acquisition of Eagle Ford Shale and Permian Basin production 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 Aseng and Alen to lower DD&A rate asset Alba field.

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

Total DD&A expense increased for 2015 as compared with 2014 due to the following:

- increase of $332 million in the DJ Basin and Marcellus Shale due to higher sales volumes and a reduction in proved reserves at year end primarily due to downward price revisions;
- increase of $93 million related to our recently-acquired Eagle Ford Shale and Permian Basin assets;
- increase of $55 million related to the Rio Grande development, deepwater Gulf of Mexico, which began producing in 2015;
- increase in Equatorial Guinea due to a reduction in proved reserves at year end primarily due to downward price revisions; and
- increase due to record sales volumes from the Tamar field, offshore Israel;

partially offset by:

- decrease of $92 million in the deepwater Gulf of Mexico due to planned downtime and maintenance and proved reserves additions; and
- decrease due to the sale of our China assets during 2014.

Changes in the unit rate per BOE for 2015 as compared with 2014 were due to increased higher-cost production volumes in the DJ Basin and deepwater Gulf of Mexico, reductions in proved reserves at year-end due to downward price revisions, offset by increased lower-cost production volumes from the Tamar field.

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

	Year Ended December 31,		
	2016	2015	2014
G&A Expense (millions)	$ 399	$ 396	$ 503
Unit Rate per BOE [1]	$ 2.64	$ 3.11	$ 4.73

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

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 for 2015 decreased as compared with 2014 primarily due to cost savings initiatives, including reduced use of contractors and consultants and decreases in special projects and other discretionary expenses, and decreases in employee personnel costs. Our total number of employees decreased from 2,735 at December 31, 2014 to 2,395 at December 31, 2015.

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 included stock-based compensation expense of $62 million in 2016, $50 million in 2015 and $63 million in 2014. See Item 8. Financial Statements and Supplementary Data – Note 12. Stock-Based and Other Compensation Plans.

Asset Impairments Asset impairment expense was as follows:

	Year Ended December 31,		
(millions)	2016	2015	2014
Asset Impairments	$ 92	$ 533	$ 500

For information regarding asset impairment charges, see Critical Accounting Policies and Estimates – Impairment of Proved Oil and Gas Properties and Other Investments and Impairment of Unproved Oil and Gas Properties and Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

Goodwill Impairment Goodwill impairment expense was as follows:

	Year Ended December 31,		
(millions)	2016	2015	2014
Goodwill Impairment	$ —	$ 779	$ —

For information regarding goodwill impairment charges, see Item 8. Financial Statements and Supplementary Data – Note 1. Summary of Significant Accounting Policies.

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

	Year Ended December 31,		
(millions)	2016	2015	2014
Marketing Expense	$ 58	$ 33	$ 16
Loss on Terminated Contract	41	—	—
Gain on Divestitures, Net	(238)	—	(73)
Corporate Restructuring Expense	8	51	—
Gain on Debt Extinguishment	(80)	—	—
Pension Plan Expense	—	88	—
Impact of Rosetta Merger	(25)	81	—
Other, Net	70	96	49
Total	$ (166)	$ 349	$ (8)

For additional information regarding items of other operating (income) expense, net, see Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information and Note 4 Noble Midstream Partners LP.

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

	Year Ended December 31,		
(millions)	2016	2015	2014
Loss (Gain) on Commodity Derivative Instruments	$ 139	$ (501)	$ (976)
Interest, Net of Amount Capitalized	328	263	210
Other Non-Operating Expense (Income), Net	9	(15)	(26)
Total	$ 476	$ (253)	$ (792)

For additional information regarding items of other (income) expense, see Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information.

Loss (Gain) on Commodity Derivative Instruments (Gain) loss on commodity derivative instruments includes:

- cash settlements (received) or paid relating to our crude oil and natural gas commodity derivative contracts, and
- non-cash (increases) or decreases in the fair values of our crude oil and natural gas commodity derivative contracts.

Year Ended December 31, 2016

Cash settlement receipts of $569 million in 2016 included:

- $499 million contributed by crude oil contracts; and
- $70 million contributed by natural gas contracts.

Non-cash decreases in fair value of $708 million in 2016 were primarily driven by the commodity price improvement that began in late 2016 and included the following:

- $582 million related to crude oil contracts; and
- $126 million related to natural gas contracts.

Year Ended December 31, 2015

Cash settlement receipts of $1.0 billion in 2015 included:

- $755 million contributed by crude oil contracts entered into by Noble and $89 million contributed by crude oil contracts acquired in the Rosetta Merger; and
- $120 million contributed by natural gas contracts entered into by Noble, $27 million contributed by natural gas contracts acquired in the Rosetta Merger and $18 million contributed by NGL contracts acquired in the Rosetta Merger.

Non-cash decreases in fair value of $508 million in 2015, were primarily driven by further declines in commodity prices and included the following:

- $423 million related to crude oil contracts;
- $65 million related to natural gas contracts; and
- $20 million related to NGL contracts.

Year Ended December 31, 2014

Cash settlement receipts of $29 million in 2014 included:

- $34 million contributed by crude oil contracts;

offset by:

- $5 million paid for natural gas contracts.

Non-cash increases in fair value of $947 million in 2014, were primarily driven by well-positioned commodity price floors amidst the commodity price downturn and included the following:

- $863 million related to crude oil contracts; and
- $84 million related to natural gas contracts.

See Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities, and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities and Note 13. Fair Value Measurements and Disclosures.

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

	Year Ended December 31,		
(millions, except per unit)	2016	2015	2014
Interest Expense	$ 412	$ 407	$ 326
Capitalized Interest	(84)	(144)	(116)
Interest Expense, Net	$ 328	$ 263	$ 210
Unit Rate per BOE [1]	$ 2.17	$ 2.07	$ 1.97

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

The increase in interest expense in 2016 as compared with 2015 is primarily due to the impact of senior notes assumed by us 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, deepwater Gulf of Mexico, which were completed in fourth quarter 2015, and Gunflint, deepwater 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 onshore US activities.

The increase in interest expense in 2015 as compared with 2014 is related to a full year of interest on senior debt issued in November 2014, as well as interest on senior notes assumed by us in the Rosetta Merger during third quarter 2015. We drew down and repaid amounts under our Revolving Credit Facility for working capital purposes. There were no other significant changes in our debt.

The increase in capitalized interest in 2015 as compared with 2014 is primarily due to higher work in progress amounts related to major long-term projects in deepwater Gulf of Mexico, offshore West Africa, and offshore Israel, as well as expansion of midstream infrastructure in the DJ Basin.

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 deepwater 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.

Other Non-operating (Income) Expense, Net Other non-operating (income) expense, net includes deferred compensation (income) expense, and other items of (income) expense, net. See Item 8. Financial Statements and Supplementary Data – Note 2. Additional Financial Statement Information.

Deferred Compensation (Income) Expense We have assets and liabilities related to a deferred compensation plan. The assets of the deferred compensation plan are held in a rabbi trust and include shares of our common stock and mutual fund investments. At December 31, 2016, approximately 30% of the market value of the assets in the rabbi trust related to our common stock. Increases in the market value of our common stock held in the trust result in the recognition of deferred compensation expense. Decreases in the market value of our common stock held in the trust result in the recognition of deferred compensation income. We recognized deferred compensation expense of $11 million in 2016 and deferred compensation income of $12 million and $25 million in 2015, and 2014, respectively. See Item 8. Financial Statements and Supplementary Data – Note 12. Stock-Based and Other Compensation Plans.

Income Tax Provision (Benefit) The income tax provision (benefit) was as follows:

	Year Ended December 31,		
(millions)	2016	2015	2014
Income Tax Provision (Benefit)	$ (787)	$ 222	$ 496
Effective Rate	44.4%	(10.0)%	29.0%

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 the 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. We endeavor to maintain a strong balance sheet and investment grade debt rating in service of these objectives.

We strive to maintain a minimum liquidity level to address volatility and risk. Traditional sources of our liquidity are cash flows from operations, cash on hand, available borrowing capacity under our Revolving Credit Facility, and proceeds from divestitures of properties. We evaluate potential strategic farm-out arrangements of our working interests for reimbursement of our capital spending. We occasionally access the capital markets and, in 2016, we generated cash of over $1.5 billion through asset sales, a working interest farm-out and the initial public offering of Noble Midstream Partners common units. We may consider repatriations of foreign cash to increase our financial flexibility and fund our capital investment program.

As of December 31, 2016, our outstanding debt (excluding capital lease and other obligations) totaled $6.7 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.

Pending Acquisition of Clayton Williams Energy, Inc. We recently executed a definitive agreement to acquire all of the outstanding common stock of Clayton Williams Energy, Inc. for $2.7 billion in Noble Energy stock and cash. We expect to assume $500 million in net debt in the transaction and intend to fund the cash portion of the acquisition through a draw on our Revolving Credit Facility. We also anticipate retiring the outstanding debt of Clayton Williams Energy assumed as part of the transaction at or following the closing. See Item 8. Financial Statements and Supplementary Data – Note 3. Acquisitions, Divestitures, and Merger.

Available Liquidity

Year-end liquidity was as follows:

	December 31,		
	2016	2015	2014
(millions, except percentages)			
Total Cash [(1)]	$ 1,209	$ 1,028	$ 1,183
Amount Available to be Borrowed Under Revolving Credit Facility [(2)]	4,000	4,000	4,000
Total Liquidity	$ 5,209	$ 5,028	$ 5,183
Total Debt [(3)]	$ 7,114	$ 7,976	$ 6,197
Noble Energy Share of Equity	9,600	10,370	10,325
Ratio of Debt-to-Book Capital [(4)]	43%	43%	38%

(1) Total cash includes cash and cash equivalents of almost $1.2 billion, which includes $57 million cash relating to Noble Midstream Partners, as well as restricted cash of $30 million related to the Permian Basin property acquisition that closed in January 2017.
(2) Excludes $350 million available to be borrowed under Noble Midstream Services Revolving Credit Facility, which is not available to Noble Energy, as of December 31, 2016. See Revolving Credit Facilities*,* below.
(3) Total debt includes capital lease and other obligations and excludes unamortized debt discount/premium, and issuance costs.
(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.

Cash and Cash Equivalents We had approximately $1.2 billion in cash and cash equivalents at December 31, 2016, compared with approximately $1.0 billion at December 31, 2015. At December 31, 2016, our cash was primarily denominated in US dollars and invested in money market funds and short-term deposits with major financial institutions. Approximately $435 million of this cash was attributable to foreign subsidiaries. We have recorded a related deferred tax liability on undistributed foreign earnings of $241 million for the future additional US tax liability for the US and foreign tax rate differences, net of estimated foreign tax credits. Our cash on hand at December 31, 2016 also included $57 million relating to Noble Midstream Partners.

Revolving Credit Facilities Noble Energy's Revolving Credit Facility of $4.0 billion committed amount matures in 2020. We expect to use the Revolving Credit Facility to fund our capital investment program and the acquisition of Clayton Williams Energy, Inc., and may periodically borrow amounts for working capital purposes. Noble Midstream Services' Revolving Credit Facility of $350 million committed amount matures in 2021. No amounts were drawn under either of these facilities at December 31, 2016. See Item 8. Financial Statements and Supplementary Data - Note 10. Long-Term Debt.

Term Loan 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. In first quarter 2016, we entered into the Term Loan Facility which provides for a three-year term loan facility for a principal amount of $1.4 billion. In connection with the Term Loan Facility, we launched cash tender offers for certain senior notes assumed in the Rosetta Merger. The borrowings under the Term Loan Facility were used solely to fund the tender offers, which resulted in a gain of $80 million. Collectively, the result of these transactions provides for significant future interest expense savings with a shorter term debt maturity.

In fourth quarter 2016, we prepaid $850 million of long-term debt outstanding under the Term Loan Facility from cash on hand. See Item 8. Financial Statements and Supplementary Data - Note 10. Long-Term Debt.

Activities Enhancing Our Liquidity Position

We were able to employ the above strategy successfully in 2016, taking steps to further position us for long-term operational performance and future growth even in a period of lower commodity prices. The following activities have further enhanced our liquidity position:

Asset Divestitures We evaluate potential strategic farm-out arrangements of our working interests for reimbursement of our capital spending and may consider asset sales or other sources of funding. We generated cash proceeds of almost $1.2 billion in 2016, $151 million in 2015 and $321 million in 2014 from asset sales and farm-out arrangements.

Noble Midstream Partners IPO On September 20, 2016, our subsidiary, Noble Midstream Partners, completed its public offering of 14,375,000 common units representing limited partner interests in Noble Midstream Partners. In connection with the offering, Noble Midstream Partners generated net proceeds of $299 million from the issuance of common units. As of December 31, 2016, we owned 1,527,584 of Noble Midstream Partners common units and 15,902,584 of Noble Midstream Partners subordinated units, which together represented a 54.8% limited partner interest.

The Noble Midstream Partners partnership agreement provides for a minimum quarterly distribution to the holders of common units and subordinated units of $0.3750 per unit for each whole quarter, or $1.5000 per unit on an annualized basis, to the extent Noble Midstream Partners has sufficient available cash after the establishment of cash reserves and the payment of certain costs and expenses. On January 26, 2017, the board of directors of Noble Midstream Partners declared a quarterly cash distribution of $0.4333 per common unit, to be paid February 14, 2017, to unitholders of record on February 6, 2017. The distribution is comprised of $0.3925 per unit for fourth quarter 2016 and $0.0411 per unit for the 10-day period following the closing of the offering through September 30, 2016.

We own all of Noble Midstream Partners subordinated units and incentive distribution rights. Upon completion of certain events as outlined in the Noble Midstream Partners partnership agreement, we will be entitled to receive additional distributions associated with these units.

We consolidate Noble Midstream Partners for financial reporting purposes; however, Noble Midstream Partners' sources of liquidity are independent of Noble Energy. See Item 8. Financial Statements and Supplementary Data - Note 1. Summary of Significant Accounting Policies.

CONE Midstream Dropdown Transaction In fourth quarter 2016, our equity investee, CONE Gathering LLC contributed its remaining 25% ownership interest in CONE Midstream DevCo I LP to CONE Midstream Partners LP. Through this transaction, we received $70 million in cash and approximately 2.6 million common units of CONE Midstream Partners LP.

Cash Dividend Repatriations During 2016, almost $1.2 billion was paid from foreign operations on an outstanding note payable, leaving a balance of approximately $710 million that can be repaid without US tax impact. During 2015, we repatriated cash dividends of $858 million from our foreign operations. We do not expect to incur significant cash tax on these repatriations due to usage of foreign tax credits and current US operating results. As of December 31, 2016, approximately $435 million of our $1.2 billion cash and cash equivalents was held by foreign subsidiaries.

Dividend Reduction On January 26, 2016, our Board of Directors adjusted the quarterly dividend to 10 cents per common share, which represents a reduction of 8 cents from fourth quarter 2015, and further enhances our liquidity.

Equity Offering In March 2015, we closed an underwritten public offering of over 24 million shares of common stock with aggregate net proceeds of approximately $1.1 billion (after deducting underwriting discounts and commissions and estimated offering expenses). We used approximately $150 million of the net proceeds to repay outstanding indebtedness under our Revolving Credit Facility which had been drawn for short-term purposes in February 2015, and the remainder was used for general corporate purposes, including the funding of our capital investment program.

In accordance with our accounting policy, we netted the intra-quarter Revolving Credit Facility activity to zero for purposes of consolidated statements of cash flows disclosure.

Current Activity – Impact on Liquidity

Due to a significant reduction in capital spending versus 2015, and significant decreases in operating expenses, we were able to substantially fund all our capital expenditures with operating cash flows in 2016. For 2017, we continue our effort to spend within cash flows and manage the Company's balance sheet and have designed a flexible capital investment program which will be responsive to changes in the commodity price environment.

The extent to which capital investment could exceed operating cash flows in the future depends on the pace of future development activities, timing of future development project sanction, the results of our exploration activities, and new business opportunities, as well as external factors such as commodity prices, among others.

Despite the volatile commodity price environment, we believe our financial capacity, coupled with our diversified portfolio, provides us with flexibility in our investment decisions including execution of development projects as well as exploration activity in the current commodity price environment. See Operating Outlook – 2017 Capital Investment Program, above.

To support our investment program, we expect that production resulting from our onshore US development programs, combined with new production from the Gunflint development project, as well as increased production at Tamar, and presuming no significant further deterioration of commodity prices, will result in an increase in cash flows which will be available to meet a portion of future capital commitments in 2017 and subsequent years.

We are currently progressing toward sanction of the Leviathan development project offshore Eastern Mediterranean. The magnitude of this discovery presents technical and financial challenges for us due to the large-scale development requirement. The first phase of Leviathan will require a multi-billion dollar investment and a number of years to complete.

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 2017. 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.*

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

We are unable to predict sudden changes in a party's creditworthiness or ability to perform. Even if we do accurately predict such sudden changes, our ability to negate these risks may be limited and we could incur significant financial losses.

Credit enhancements have been obtained from some parties in the form of parental guarantees, letters of credit or credit insurance; however, not all of our counterparty credit is protected through guarantees or credit support. In addition, we maintain credit insurance associated with specific purchasers. However, nonperformance by a trade creditor, hedge counterparty or financial institution could result in significant financial losses. See Item 1A. Risk Factors – *We are exposed to counterparty credit risk as a result of our receivables, hedging transactions and cash investments.*

Cash Flows

Summary cash flow information is as follows:

	Year Ended December 31,		
	2016	2015	2014
(millions)			
Total Cash Provided By (Used in)			
Operating Activities	$ 1,351	$ 2,062	$ 3,506
Investing Activities	(431)	(2,871)	(4,465)
Financing Activities	(768)	654	1,025
Increase (Decrease) in Cash and Cash Equivalents	$ 152	$ (155)	$ 66

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

Net cash provided by operating activities for 2015 decreased as compared with 2014. Decreases in average realized commodity prices were partially offset by higher settlements of commodity derivative instruments and increases in sales volumes. Working capital changes resulted in a $129 million operating cash flow reduction in 2015 as compared with a positive impact of $412 million in 2014.

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

Capital spending for property, plant and equipment totaled $1.5 billion in 2016, or nearly half, as compared with 2015, primarily due to the Rosetta Merger in 2015 and the timing of completion of major project development activities in the Gulf of Mexico. We received approximately $1.2 billion of proceeds from asset divestitures during 2016 as compared with $151 million of proceeds from divestitures during 2015. We invested $8 million in CONE Gathering, and received cash distributions of $70 million, accounted for as investing activity, from CONE Midstream, during 2016.

Capital spending for property, plant and equipment totaled $3.0 billion in 2015, 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.

Capital spending for property, plant and equipment totaled $4.9 billion in 2014, representing an increase of $924 million as compared with 2013, primarily due to increased major project development activity in our operational areas. We invested $71 million in CONE Gathering, and received cash distributions of $156 million, accounted for as investing activity, from CONE Midstream, during 2014. We also received $321 million proceeds from non-strategic asset divestitures during 2014.

Financing Activities Our financing activities include the issuance or repurchase of our common stock, payment of cash dividends on our common stock, the borrowing of cash and the repayment of borrowings.

In 2016, net cash used in financing activities was $768 million. We used Term Loan proceeds of $1.4 billion to repay $1.4 billion of senior notes. We subsequently repaid $850 million of the Term Loan 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 shares of our common stock ($4 million).

In 2015, net cash provided by financing activities was $654 million. 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 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).

In 2014, net cash provided by financing activities was $1.0 billion. We received approximately $1.5 billion net proceeds from the issuance of senior notes. Funds were also provided by cash proceeds from, and tax benefits related to, the exercise of stock options ($67 million). We used cash to repay senior notes due ($200 million), pay dividends on our common stock ($249 million), make principal payments related to capital lease obligations ($55 million), and repurchase shares of our common stock ($16 million).

Acquisition, Capital and Other Exploration Expenditures

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

	Year Ended December 31,		
	2016	2015	2014
(millions)			
Acquisition, Capital and Exploration Expenditures			
Proved Property Acquisition (1)	$ —	$ 1,613	$ —
Unproved Property Acquisition (2)	234	1,480	249
Exploration	222	322	505
Development	1,017	2,055	3,660
Midstream(3)	42	356	229
Corporate and Other	50	97	169
Total	$ 1,565	$ 5,923	$ 4,812
Other			
Investment in Equity Method Investee (4)	$ 8	$ 104	$ 71
Increase in Capital Lease Obligations (5)	5	55	110

(1) Proved property acquisition costs for 2015 relates to proved properties acquired in the Rosetta Merger. See Item 8. Financial Statements and Supplementary Data - Note 3. Acquisitions, Divestitures and Merger.

(2) 2016 unproved property acquisition costs relate to the termination of the Marcellus Shale joint development. Costs in 2015 primarily relate to unproved properties acquired in the Rosetta Merger. See Item 8. Financial Statements and Supplementary Data - Note 3. Acquisitions, Divestitures and Merger. Additionally, unproved property acquisition cost for 2015 includes $49 million in the DJ Basin, $60 million in the Marcellus Shale, and $10 million and $5 million for costs incurred after the Rosetta Merger in the Permian Basin and Eagle Ford Shale, respectively.
Unproved property acquisition cost for 2014 includes $68 million in the DJ Basin, $160 million in the Marcellus Shale and $16 million in the deepwater Gulf of Mexico.

(3) 2016 includes expenditures of Noble Midstream Partners, and 2015 includes midstream assets acquired in the Rosetta Merger. See Item 8. Financial Statements and Supplementary Data - Note 3. Acquisitions, Divestitures and Merger.

(4) We own a 50% interest in CONE Gathering which is accounted for using the equity method. CONE Gathering constructs, owns and operates gathering lines and facilities related to the Marcellus Shale development.

(5) Relates to onshore US assets.

Total expenditures decreased during 2016 as compared with 2015, excluding the Rosetta Merger, as we responded to the lower commodity price environment.

Excluding the Rosetta Merger, total expenditures decreased in 2015 as compared with 2014 due to 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.

Asset Divestitures Asset divestitures generated cash proceeds of approximately $1.2 billion in 2016, $151 million in 2015 and $321 million in 2014.

Risk and Insurance Program

Our business is subject to all of the inherent and unplanned operating risks normally associated with the exploration, production, gathering, processing, transportation and marketing of crude oil, natural gas and NGLs. Such risks include hurricanes, earthquakes, blowouts, well cratering, fire, loss of well control, pipeline disruptions, mishandling of fluids and chemicals and possible underground migration of hydrocarbons and chemicals, any of which could result in damage to, or destruction of, crude oil and natural gas wells or formations or production facilities and other property, environmental pollution, injury to persons, or loss of life. As protection against financial loss resulting from many, but not all of these operating hazards, we maintain insurance coverage, including certain physical damage, business interruption (loss of production income), employer's liability, third party liability and worker's compensation insurance. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our potential risks of loss and the cost and availability of insurance and the company's ability to sustain uninsured losses, and revise our insurance program accordingly. Limits and deductibles were revised for the property and business interruption programs, as well as the excess liability program, in 2016.

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

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

In the Gulf of Mexico, we self-insure for windstorm related exposures, unless contractually required to purchase windstorm coverage for third party facilities. Currently, our Gulf of Mexico assets are primarily subsea operations; therefore, our direct windstorm exposure is limited. However, we do have some exposure through the use of third party production platforms and one Noble-owned floating production facility. In addition, the cost of windstorm insurance continues to be very expensive and coverage amounts are limited. As a result, we currently believe it is more cost-effective for us to self-insure, or absorb any physical loss or damage to these assets, including any business interruption attributable to windstorm exposures. We continually assess our offshore insurance needs in response to our changing business requirements.

As is customary with industry practice, crude oil and natural gas well owners generally indemnify drilling rig contractors against certain risks, such as those arising from property and environmental losses, pollution from sources such as oil spills, or contamination resulting from well blowout or fire or other uncontrolled flow of hydrocarbons. Most of our US and international drilling contracts contain such indemnification clauses. In addition, crude oil and natural gas well owners typically assume all costs of well control in the event of an uncontrolled well. We currently carry more than $1.05 billion in insurance protection, depending on our ownership interest, for potential financial losses occurring as a result of events such as the Deepwater Horizon incident of 2010. This protection consists of $850 million of well control, pollution cleanup and consequential damages coverage and more than $200 million of additional pollution cleanup and consequential damages coverage, which also covers third-party personal injury and death.

We have contracts with third-party service providers to perform hydraulic fracturing operations for us. The master service agreements signed by hydraulic fracturing contractors contain indemnification provisions similar to those noted above. Our liability insurance policies do not contain any specific exclusion for liabilities from hydraulic fracturing operations and we believe our policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies. We do not have insurance for gradual pollution nor do we have coverage for penalties or fines that may be assessed by a governmental authority.

We expect the future availability and cost of insurance to be impacted by the various catastrophic events and large losses that insurers have incurred over the past several years. Impacts could include tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums.

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

We are a member in Oil Insurance Limited (OIL). OIL is a mutual insurance company which insures property, pollution liability, control of well and other catastrophic risks. See Contractual Obligations below for a discussion of our theoretical withdrawal premium liability.

We maintain membership in Clean Gulf Associates (CGA), a nonprofit association of production and pipeline companies operating in the Gulf of Mexico. See Items 1. and 2. Business and Properties – Oil Spill Response Preparedness.

Financing Activities

Long-Term Debt Our long-term debt totaled $6.7 billion (excluding capital lease and other obligations) at December 31, 2016, with maturities ranging from 2019 to 2097.

Debt Refinancing On January 6, 2016, we announced a series of transactions, consisting of a new term loan (New Term Loan) and cash tender offers for certain outstanding notes, which collectively enhances our financial flexibility and results in future interest expense savings. The New Term Loan is a three-year agreement, due January 6, 2019, with seven lending institutions for a principal amount of up to $1.4 billion. Provisions of the New Term Loan agreement, including pricing and covenants, are consistent with those contained in our existing Revolving Credit Facility. Borrowings under the New Term Loan agreement may be pre-paid in full or in part at any time prior to its maturity without premium.

In connection with the New Term Loan commitments, we simultaneously launched cash tender offers for the following series of our notes: 5.875% Senior Notes due 2024, 5.875% Senior Notes due 2022 and 5.625% Senior Notes due 2021, all of which were originally assumed as part of the Rosetta Merger. The maximum aggregate purchase price (exclusive of accrued interest) of the notes to be purchased, plus fees, was limited to $1.4 billion and funded by borrowings under the New Term Loan. As a result, we recognized a gain of $80 million which is reflected in other operating (income) expense, net in our consolidated statements of operations.

In fourth quarter 2016, we prepaid $850 million of borrowings under the Term Loan Facility from cash on hand.

See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

Credit Facilities Our principal source of liquidity is our Revolving Credit Facility that matures August 27, 2020. During 2015, we entered into the Second Amendment to Credit Agreement (Second Amendment) which, among other things, extended the maturity date of the Revolving Credit Facility from October 3, 2018 to August 27, 2020.

Our Revolving Credit Facility is available for general corporate purposes and has a commitment of $4.0 billion through the maturity date. Certain lenders that are a party to the Credit Agreement 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.

At December 31, 2016, there were no amounts outstanding under the Revolving Credit Facility, leaving the entire $4.0 billion available for use. We may rely on our Revolving Credit Facility to help fund our capital investment program and may periodically borrow amounts for working capital purposes. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

Noble Midstream Partners IPO On September 20, 2016, Noble Midstream Partners, one of our subsidiaries, completed its public offering of 14,375,000 common units representing limited partner interests in Noble Midstream Partners. In connection with the offering, Noble Midstream Partners generated net proceeds of $299 million from the issuance of common units. See Item 8. Financial Statements and Supplementary Data – Note 4. Noble Midstream Partners LP.

Public Debt Offerings We occasionally enter into public debt offerings to increase our liquidity. On November 7, 2014, we completed an offering of $650 million senior unsecured 3.90% notes due November 15, 2024 and $850 million senior unsecured 5.05% notes due November 15, 2044. Net proceeds were used to repay outstanding indebtedness under our Revolving Credit Facility and for general corporate purposes.

Capital Lease and Other Obligations We occasionally enter into lease agreements for operating assets or corporate buildings that are accounted for as capital leases. Capital leases are included in debt in our consolidated balance sheets. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

Fixed-Rate Debt Our outstanding fixed-rate debt (excluding capital lease and other obligations) totaled $6.1 billion at December 31, 2016. The weighted average interest rate on fixed-rate debt was 5.69%, with maturities ranging from 2019 to 2097. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

Ratio of Debt-to-Book Capital Our ratio of debt-to-book capital remained flat at 43% year to year. Significant changes in our financial position impacting the ratio included the following:

- $1.0 billion net decrease in debt;

offset by:

- $172 million decrease in shareholders' equity from dividends paid; and
- $1.0 billion decrease in shareholders' equity from current year net loss.

Cash Interest Payments We made cash interest payments related to our outstanding debt of $412 million in 2016, $404 million in 2015, and $305 million in 2014.

Exercise of Stock Options Proceeds from the exercise of stock options totaled $24 million in 2016, $8 million in 2015 and $48 million in 2014. Proceeds received from the exercise of stock options fluctuate primarily based on the number of options exercised which is influenced by the price at which our common stock trades on the NYSE in relation to the exercise price of the options issued.

Dividends We paid cash dividends totaling 40 cents per common share in 2016, 68 cents per common share in 2015 and 55 cents per common share in 2014.

On January 24, 2017, our Board of Directors declared a quarterly cash dividend of 10 cents per common share payable on February 21, 2017, to the shareholders of record at the close of business on February 6, 2017.

The amount of future dividends will be determined on a quarterly basis at the discretion of our Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Common Stock Repurchases We receive shares of our common stock from employees for the payment of withholding taxes due on the vesting of restricted shares issued under stock-based compensation plans. We received approximately 237,000 shares with a total value of $8 million in 2016, 491,000 shares with a total value of $21 million in 2015, and 255,000 shares with a total value of $16 million in 2014.

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, 2016, the material off-balance sheet arrangements and transactions that we have entered into included drilling rig contracts, operating lease agreements, and undrawn letters of credit, all of which are customary in the oil and gas industry.

Termination of Marcellus Shale Joint Development Agreement In late 2016, we and CONSOL agreed to terminate our Joint Development Agreement and extinguish the carried cost obligation. See Items 1. and 2. Business and Properties – Marcellus Shale.

Other Other than the off-balance sheet arrangements listed above, 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, 2016 that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes. Unless otherwise noted, the table excludes amounts related to Noble Midstream Partners, and all amounts shown are net to our interest.

Obligation	Total	2017	2018 and 2019	2020 and 2021	2022 and beyond
(millions)					
Long-Term Debt [1]	$ 6,739	$ —	$ 1,550	$ 1,379	$ 3,810
Interest Payments [2]	5,347	363	646	523	3,815
Capital Lease and Other Obligations [3]	461	77	131	90	163
Drilling and Equipment Obligations [4]	130	128	2	—	—
Purchase Obligations [5]	339	127	146	36	30
Transportation and Gathering [6]	2,954	250	626	512	1,566
Operating Lease Obligations [7]	346	30	72	56	188
Other Liabilities [8]					
Asset Retirement Obligations [9]	935	162	117	56	600
Commodity Derivative Instruments [10]	116	102	14	—	—
Total Contractual Obligations	$ 17,367	$ 1,239	$ 3,304	$ 2,652	$ 10,172

(1) Long-term debt excludes our capital lease and other obligations. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

(2) Interest payments are based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2016. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

(3) Annual capital lease payments, net to our interest, exclude regular maintenance and operational costs. See Item 8. Financial Statements and Supplementary Data – Note 10. Long-Term Debt.

(4) Drilling and equipment obligations represent our working interest share of contractual agreements with third-party service providers to procure drilling rigs, such as the Atwood Advantage drill ship, and other related equipment for exploratory and development drilling activities. See Counterparty Credit Risk, above, and Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

(5) 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, and Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

(6) 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 Commitments. See Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

(7) 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. See Item 8. Financial Statements and Supplementary Data – Note 18. Commitments and Contingencies.

(8) The table excludes deferred compensation liabilities of $218 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data – Note 12. Stock-Based and Other Compensation Plans.

(9) Asset retirement obligations are discounted. See Item 8. Financial Statements and Supplementary Data – Note 9. Asset Retirement Obligations.

(10) Amount represents open commodity derivative instruments that were in a net payable position with the counterparty at December 31, 2016. See Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities.

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 onshore US assets are held through continuous development obligations. Therefore, we are contractually obligated to fund a level of development activity in these areas and failure to meet these obligations may result in the loss of a lease.

Leviathan Natural Gas Project Timing of the Leviathan project sanction depends on numerous factors, including completion of necessary marketing activities, engineering and construction planning and availability of funds from us and our partners to invest in the project. We have made significant progress on these fronts and are nearing project sanction. Upon sanction of the Leviathan project, we expect to enter into several contractual agreements for the construction of facilities and development of the Leviathan field.

OIL Contingency As of December 31, 2016, we accrued approximately $18 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, 2016.

Letters of Credit In the ordinary course of business, we maintain letters of credit with a variety of banks in support of certain performance obligations of our subsidiaries. Outstanding letters of credit totaled approximately $122 million at December 31, 2016.

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.

Other

Pension Plan In 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 expensed all remaining unamortized prior service costs and actuarial losses from accumulated other comprehensive loss (AOCL). During 2015, we expensed $88 million related to the pension plan termination.

Income Taxes We made cash payments for income taxes, net of refunds, of $236 million in 2016, $202 million in 2015 and $150 million in 2014.

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 All of the reserves data in this 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 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. Uncertainties include the projection of future production rates and the expected timing of development expenditures. 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. In addition, economic producibility of reserves is dependent on the commodity prices used in the reserves estimate. Our reserves estimates are based on 12-month average commodity prices, unless contractual arrangements designate the price to be used, in accordance with SEC rules. However, crude oil and natural gas prices are volatile and, as a result, our reserves estimates will change in the future.

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 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 We account for crude oil and natural gas properties under the successful efforts method of accounting. Under the successful efforts method, costs to acquire mineral interests in crude oil and natural gas properties, drill and equip exploratory wells that find commercial quantities of proved reserves, and drill and equip development wells are capitalized. Proved property acquisition costs 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 to drill and equip exploratory wells that find proved reserves and drill and equip development wells are also amortized to expense by the unit-of-production method on a field-by-field basis. These costs, along with support equipment and facilities, are amortized based on proved developed crude oil, natural gas and NGL reserves. 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. Application of the successful efforts method results in the 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 noncommercial.

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. 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.

Exploratory Well Costs In accordance with the successful efforts method of accounting, the 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 the well has 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 deepwater 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.

Management assesses the status of suspended exploratory well costs on a quarterly basis. These costs may be charged to exploration expense in future periods if we decide not to pursue additional exploratory or development activities.

At December 31, 2016, the balance of property, plant and equipment included $768 million of suspended exploratory well costs, $699 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 2016, previously capitalized exploratory well costs of $525 million were expensed. See Item 8. Financial Statements and Supplementary Data – Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

Impairment of Proved Oil and Gas Properties and Other Investments 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, revenues and operating and development costs. Negative revisions in estimates of reserves quantities or expectations of falling commodity prices, rising operating or development costs, or changes in intended use could result in a reduction in undiscounted future net cash flows and could indicate property impairment.

We recorded total pre-tax (non-cash) asset impairment charges of $92 million in 2016, $533 million in 2015 and $500 million in 2014 for proved oil and gas properties and other investments. See Item 8. Financial Statements and Supplementary Data – Note 5. Asset Impairments.

Impairment of Unproved Oil and Gas Properties We also perform assessments of individually significant unproved crude oil and natural gas properties for impairment on a quarterly basis and recognize a loss with a charge to exploration expense 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 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.

At December 31, 2016, the net book value of our unproved properties includes significant amounts allocated in previous business combinations or acquisitions, including the Rosetta Merger and Marcellus Shale joint venture. See Supplemental Oil and Gas Disclosures (Unaudited) – Capitalized Costs Related to Oil and Gas Producing Properties.

Negative revisions in estimated reserves quantities, reductions in commodity prices, or increases in estimated costs could cause a reduction in the value of an unproved property and, therefore, could also cause a reduction in the carrying amount of the property. 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 for determining the amount of the impairment loss to record. The estimated prices used in the cash flow analysis are determined by management based on forward commodity price curves as of the date of the estimate, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk-weighting factors.

Due to the volatility of crude oil, natural gas and NGL prices, these cash flow estimates are inherently imprecise. Management's assessment of the results of exploration activities, availability of funds for future activities and the current and projected political and regulatory climate in areas in which we operate also impact the amounts and timing of impairment provisions.

Purchase Price Allocations We occasionally acquire assets and assume liabilities in transactions accounted for as business combinations, such as 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.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we 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 must prepare estimates. To estimate the fair values of these properties, we prepare estimates 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 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.

Estimated fair values assigned to assets acquired 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. Acquisitions, Divestitures and Merger.

Derivative Instruments and Hedging Activities

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. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. All commodity derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net payable position with a fair value of $116 million at December 31, 2016. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. We then discount the cash inflows or outflows using a combination of published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of our commodity derivative assets and liabilities include a measure of credit risk based on current published credit default swap rates. In addition, for collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters.

Changes in the fair values of our commodity derivative instruments have a significant impact on our net income (loss) because we apply mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur. For the year ended December 31, 2016, we reported net loss on commodity derivative instruments of $139 million.

We compare our estimates of the fair values of our commodity derivative instruments with those provided by our counterparties. There have been no significant differences. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk and Interest Rate Risk and Item 8. Financial Statements and Supplementary Data – Note 8. Derivative Instruments and Hedging Activities and Note 13. Fair Value Measurements and Disclosures.

Asset Retirement Obligations Our ARO 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, which is when we have an existing legal obligation associated with the retirement of our oil and gas properties and the obligation can reasonably be estimated. The associated asset retirement cost is capitalized as part of the carrying cost of the oil and gas asset. 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 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. Asset retirement obligations totaled $935 million at December 31, 2016. See Item 8. Financial Statements and Supplementary Data – Note 9. Asset Retirement Obligations.

Income Tax Expense and Deferred Tax Assets 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, 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. Any increases or decreases in a deferred tax asset valuation allowance would impact net income through offsetting changes in income tax expense.

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

Recently Issued Accounting Standards Updates See Item 8. Financial Statements and Supplementary Data – Note 1. Summary of Significant Accounting Policies.

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, as the volatility of crude oil and natural gas prices continues to impact the oil and gas industry. Due to commodity price volatility, we may use derivative instruments as a means of managing our exposure to price changes.

At December 31, 2016, 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, 2016 with a fair value of $116 million. Based on the December 31, 2016 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 $83 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 $40 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 2017 revenues and results of operations will be adversely affected if commodity prices remain at current levels or decline further. In the current commodity price environment, we are unlikely to hedge future revenues at the same level as our previous hedging arrangements. As such, our revenues will be more susceptible to commodity price volatility as our commodity price derivatives settle and are not replaced.

While we use commodity derivative instruments to mitigate our exposure to commodity price risk, thereby mitigating our exposure to price declines, these instruments may also limit our potential cash flows in periods of rising commodity prices or even place us in a liability position respective to our counterparties. For example, should commodity prices increase, certain of our swaptions are likely to be extended by our counterparties which could require us to pay monthly cash settlements if market prices exceed the contracted swap prices.

See Item 1A. Risk Factors – *Commodity hedging transactions may limit our potential gains or fail to protect us from declines in commodity prices,* Critical Accounting Policies and Estimates – Derivative Instruments and Hedging Activities 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 Revolving Credit Facility and the amount of interest we earn on our short-term investments.

At December 31, 2016, we had approximately $6.7 billion (excluding capital lease and other obligations) of long-term debt outstanding. Excluding our Term Loan Facility, all debt outstanding was fixed-rate debt, with a weighted average interest rate of 5.69% at December 31, 2016. 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. As of December 31, 2016, our cash and cash equivalents totaled approximately $1.2 billion, approximately 70% 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 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, such as foreign deferred tax liabilities in certain foreign tax jurisdictions, are denominated in a foreign currency. During 2016, the US dollar gained in value against other currencies. However, 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 2016, 2015 and 2014. 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

INDEX TO FINANCIAL STATEMENTS

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, 2016, 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, 2016, 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, 2016 which is included herein.

Noble Energy, Inc.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Noble Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2016 and 2015, 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, 2016. 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 conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Noble Energy, Inc. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the years in the three‑year period ended December 31, 2016, 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), Noble Energy Inc.'s internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 14, 2017 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 14, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Noble Energy, Inc.:

We have audited Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Noble Energy, Inc.'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 Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 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.

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.

In our opinion, Noble Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2016 and 2015, 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, 2016, and our report dated February 14, 2017 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 14, 2017

Noble Energy, Inc.
Consolidated Statements of Operations
(millions, except per share amounts)

	Year Ended December 31,		
	2016	2015	2014
Revenues			
Oil, Gas and NGL Sales	$ 3,389	$ 3,093	$ 4,945
Income from Equity Method Investees	102	90	170
Total Revenues	3,491	3,183	5,115
Costs and Expenses			
Production Expense	1,083	979	945
Exploration Expense	925	488	498
Depreciation, Depletion and Amortization	2,454	2,131	1,759
General and Administrative	399	396	503
Asset Impairments	92	533	500
Goodwill Impairment	—	779	—
Other Operating (Income) Expense, Net	(166)	349	(8)
Total Operating Expenses	4,787	5,655	4,197
Operating (Loss) Income	(1,296)	(2,472)	918
Other (Income) Expense			
Loss (Gain) on Commodity Derivative Instruments	139	(501)	(976)
Interest, Net of Amount Capitalized	328	263	210
Other Non-Operating Expense (Income), Net	9	(15)	(26)
Total Other Expense (Income)	476	(253)	(792)
(Loss) Income Before Income Taxes	(1,772)	(2,219)	1,710
Income Tax (Benefit) Provision	(787)	222	496
Net (Loss) Income Including Noncontrolling Interests	(985)	(2,441)	1,214
Less: Net Income Attributable to Noncontrolling Interests	13	—	—
Net (Loss) Income Attributable to Noble Energy	$ (998)	$ (2,441)	$ 1,214
Net (Loss) Income Attributable to Noble Energy per Share of Common Stock			
Basic	$ (2.32)	$ (6.07)	$ 3.36
Diluted	$ (2.32)	$ (6.07)	$ 3.27
Weighted Average Number of Shares Outstanding			
Basic	430	402	361
Diluted	430	402	367

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,		
	2016	2015	2014
Net (Loss) Income Including Noncontrolling Interests	$ (985)	$ (2,441)	$ 1,214
Other Items of Comprehensive Income (Loss)			
Net Change in Mutual Fund Investment	—	(11)	—
Less Tax Expense	—	4	—
Net Change in Pension and Other	3	99	42
Less Tax (Benefit) Expense	(1)	(35)	(15)
Other Comprehensive Income (Loss)	2	57	27
Comprehensive (Loss) Income Including Noncontrolling Interests	$ (983)	$ (2,384)	$ 1,241
Less: Comprehensive Income Attributable to Noncontrolling Interests	13	—	—
Comprehensive (Loss) Income Attributable to Noble Energy	$ (996)	$ (2,384)	$ 1,241

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

Noble Energy, Inc.
Consolidated Balance Sheets
(millions)

	December 31, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,180	$ 1,028
Accounts Receivable, Net	615	450
Commodity Derivative Assets	—	582
Other Current Assets	160	216
Total Current Assets	1,955	2,276
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method of Accounting)	30,355	31,220
Property, Plant and Equipment, Other	909	858
Total Property, Plant and Equipment, Gross	31,264	32,078
Accumulated Depreciation, Depletion and Amortization	(12,716)	(10,778)
Total Property, Plant and Equipment, Net	18,548	21,300
Other Noncurrent Assets	508	620
Total Assets	$ 21,011	$ 24,196
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable - Trade	$ 736	$ 1,128
Other Current Liabilities	742	677
Total Current Liabilities	1,478	1,805
Long-Term Debt	7,011	7,976
Net Deferred Income Tax Liability	1,819	2,826
Other Noncurrent Liabilities	1,103	1,219
Total Liabilities	11,411	13,826
Shareholders' Equity		
Preferred Stock - Par Value $1.00 per share; 4 Million Shares Authorized, None Issued	—	—
Common Stock - Par Value $0.01; 1 Billion and 500 Million Shares Authorized; 471 Million and 470 Million Shares Issued, Respectively	5	5
Additional Paid in Capital	6,450	6,360
Accumulated Other Comprehensive Loss	(31)	(33)
Treasury Stock, at Cost; 38 Million Shares	(692)	(688)
Retained Earnings	3,556	4,726
Noble Energy Share of Equity	9,288	10,370
Noncontrolling Interests	312	—
Total Equity	9,600	10,370
Total Liabilities and Equity	$ 21,011	$ 24,196

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

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

	Year Ended December 31,		
	2016	2015	2014
Cash Flows From Operating Activities			
Net (Loss) Income Including Noncontrolling Interests	$ (985)	$ (2,441)	$ 1,214
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities			
Depreciation, Depletion and Amortization	2,454	2,131	1,759
Asset Impairments	92	533	500
Goodwill Impairment	—	779	—
Dry Hole Cost	579	266	226
Deferred Income Taxes	(984)	116	268
Loss (Gain) on Commodity Derivative Instruments	139	(501)	(976)
Net Cash Received in Settlement of Commodity Derivative Instruments	569	1,009	29
Gain on Divestitures	(238)	—	(73)
Stock Based Compensation	77	86	87
Non-cash Pension Plan Termination Expense	—	82	—
Gain on Debt Extinguishment	(80)	—	—
Undeveloped Leasehold Impairment	93	21	—
Expiration and Amortization of Unproved Leaseholds	55	92	43
Other Adjustments for Noncash Items Included in Income	40	18	17
Changes in Operating Assets and Liabilities, Net of Assets Acquired and Liabilities Assumed			
(Increase) Decrease in Accounts Receivable	(164)	453	29
(Decrease) Increase in Accounts Payable	(111)	(364)	318
(Decrease) Increase in Current Income Taxes Payable	(32)	(94)	18
(Decrease) Increase in Other Current Liabilities	(63)	(70)	45
Other Operating Assets and Liabilities, Net	(90)	(54)	2
Net Cash Provided by Operating Activities	1,351	2,062	3,506
Cash Flows From Investing Activities			
Additions to Property, Plant and Equipment	(1,541)	(2,979)	(4,871)
Proceeds from Divestitures	1,241	151	321
Marcellus Shale Acreage Exchange Consideration	(213)	—	—
Cash Acquired in Rosetta Merger	—	61	—
Additions to Equity Method Investments	(8)	(104)	(71)
Distributions from Equity Method Investments	70	—	156
Other	20	—	—
Net Cash Used in Investing Activities	(431)	(2,871)	(4,465)
Cash Flows From Financing Activities			
Dividends Paid, Common Stock	(172)	(291)	(249)
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	299	—	—
Proceeds from Noble Revolving Credit Facility	—	—	1,050
Repayment of Noble Revolving Credit Facility	—	—	(1,050)
Repayment of Revolving Credit Facility Assumed in Rosetta Merger	—	(70)	—
Proceeds from Term Loan Facility	1,400	—	—
Repayment of Term Loan Facility	(850)	—	—
Proceeds from Issuance of Senior Notes, Net	—	—	1,478
Repayment of Senior Notes	(1,383)	(12)	(200)
Repayment of Capital Lease Obligation	(53)	(67)	(55)
Other	(9)	(18)	51
Net Cash (Used in) Provided By Financing Activities	(768)	654	1,025
Increase (Decrease) in Cash and Cash Equivalents	152	(155)	66
Cash and Cash Equivalents at Beginning of Period	1,028	1,183	1,117
Cash and Cash Equivalents at End of Period	$ 1,180	$ 1,028	$ 1,183

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

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

	Attributable to Noble Energy						
	Common Stock (1)	Additional Paid in Capital	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Non-controlling Interests	Total Equity
December 31, 2013	$ 4	$ 3,463	$ (117)	$ (659)	$ 6,493	—	$ 9,184
Net Income	—	—	—	—	1,214	—	1,214
Stock-based Compensation	—	87	—	—	—	—	87
Exercise of Stock Options	—	48	—	—	—	—	48
Tax Benefits Related to Exercise of Stock Options	—	19	—	—	—	—	19
Dividends (68 cents per share)	—	—	—	—	(249)	—	(249)
Net Change in Other	—	7	27	(12)	—	—	22
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
Tax Benefits Related to Exercise of Stock Options	—	(1)	—	—	—	—	(1)
Dividends (72 cents per share)	—		—	—	(291)	—	(291)
Issuance of Shares of Common Stock to Public, Net of Offering Costs	—	1,112	—	—	—	—	1,112
Net Change in Other	—	3	57	(17)	—	—	43
December 31, 2015	$ 5	$ 6,360	$ (33)	$ (688)	$ 4,726	—	$ 10,370
Net Income (Loss)	—	—	—	—	(998)	13	(985)
Stock-based Compensation	—	68	—	—	—	—	68
Exercise of Stock Options	—	24	—	—	—	—	24
Tax Benefits Related to Exercise of Stock Options	—	(6)	—	—	—	—	(6)
Dividends (40 cents per share)	—	—	—	—	(172)	—	(172)
Issuance of Noble Midstream Partners Common Units, Net of Offering Costs	—	—	—	—	—	299	299
Net Change in Other	—	4	2	(4)	—	—	2
December 31, 2016	$ 5	$ 6,450	$ (31)	$ (692)	$ 3,556	312	$ 9,600

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

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 in our Marcellus Shale and West Africa operating areas. 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 revenue in our consolidated statements of operations.

We carry equity method investments at our share of net assets of the equity investees plus our loans and advances. 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. 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 4. Noble Midstream Partners LP.

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 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 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 and asset retirement obligations, 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. Further 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).

Reclassification Certain reclassifications have been made to the 2015 and 2014 consolidated financial statements to conform to the 2016 presentation. These reclassifications were not material to the financial statements.

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. Repairs and maintenance 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 2016, 2015 and 2014 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 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 an unproved property impairment charge in 2016. It is possible that unproved oil and gas properties could become impaired in the future if commodity prices decline. 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 for sale oil and gas properties. At the end of each reporting period, we evaluate our 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 3. 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 deepwater 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 3 to 30 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 $84 million in 2016, $144 million in 2015, and $116 million in 2014.

Asset Retirement Obligations Asset retirement obligations 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 our DD&A expense in the statement 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 Goodwill represents the excess of the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed. Goodwill is subject to annual impairment testing in December (or more frequently as circumstances dictate). During 2015, we reviewed our goodwill balance 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 our goodwill could have fallen below its book value. As of December 31, 2015, we determined that our goodwill was fully impaired and recognized a loss of $779 million.

Our goodwill related primarily to the excess purchase price over amounts assigned to assets and liabilities from the Rosetta Merger in 2015 and the Patina Merger in 2005 and was associated with our US reporting unit. During 2015, goodwill increased $163 million due to the Rosetta Merger and decreased $4 million due to allocations of goodwill to onshore US properties sold.

For purposes of determining the 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.

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 includes the non-cash portion of gain and loss on commodity derivative instruments, which represented 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 arrangement 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 our cash-settled awards utilizing the liability method as defined under Accounting Standards Codification Topic 718, *Compensation - Stock Compensation*. The fair value of liability awards is remeasured at each reporting date, based on the fair market value of a share of common stock of the Company as of the reporting date, through the settlement date with the change in fair value recognized as compensation expense over that period. 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 defined benefit pension, restoration and other postretirement benefit plans in the consolidated balance sheets, with a corresponding adjustment to AOCL, net of tax. The amount remaining in AOCL at December 31, 2016 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 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.

In addition, we provide a deferred tax liability for the US and foreign tax rate differences for the future additional US tax liability on accumulated undistributed foreign earnings of our foreign subsidiaries, net of estimated foreign tax credits. 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.

Historically, we had certain immaterial domestic natural gas sales agreements for which we previously used the entitlement method to account for imbalances. In 2016, we divested assets which were subject to this accounting and therefore, we no longer have contracts that are accounted for under the entitlement method.

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 18. 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 15. Segment Information.

Changes in Shareholders' Equity On April 28, 2015, our shareholders voted to approve an amendment to the Company's Certificate of Incorporation to increase the number of authorized shares of our common stock from 500 million to 1 billion shares.

Recently Issued Accounting Standards

Consolidation - Interests Held through Related Parties That Are under Common Control In October 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2016-17 (ASU 2016-17): *Consolidation - Interests Held through Related Parties That Are under Common Control.* The update changes the process through which a reporting entity determines whether it is the primary beneficiary of a variable interest entity (VIE). As a result, the single decision maker of a VIE uses economic exposure to determine its classification as the primary beneficiary as opposed to evaluating which party is most closely associated with the VIE. In February 2015, the FASB issued ASU 2015-02, which changed the guidance as to whether an entity is a variable interest entity (VIE) or a voting interest entity and how related parties are considered in the VIE model. During third quarter 2016, Noble Midstream Partners closed on its initial public offering of common units. Under the provisions of both Accounting Standards Updates, Noble Midstream Partners is considered a VIE, and Noble Energy is considered the primary beneficiary of that VIE. We have adopted these provisions, which did not have a material effect on our consolidated financial statements or related disclosures.

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. This ASU also requires disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. The standard will be effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted. In the normal course of business, we enter into capital and operating lease agreements to support our exploration and development operations and lease assets such as drilling rigs, platforms, storage facilities, field services and well equipment, pipeline capacity, office space and other assets. We believe the adoption and implementation of this ASU will likely have a material impact on our balance sheet resulting from an increase in both assets and liabilities relating to our leasing activities. As part of our assessment to date, we have formed an implementation work team, prepared educational and training materials pertinent to this ASU and have begun contract review and documentation.

Compensation - Stock Compensation In March 2016, the FASB issued Accounting Standards Update No. 2016-09 (ASU 2016-09): *Compensation - Stock Compensation*, to reduce complexity and enhance several aspects of accounting and disclosure for share-based payment transactions, including the accounting for income taxes, award forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The ASU will be effective for annual and interim periods beginning after December 15, 2016, with earlier application permitted. Certain aspects of this guidance will require retrospective application while other aspects are to be applied prospectively. Based upon our evaluation, the adoption of this ASU will not have a material effect on our consolidated financial statements or related disclosures.

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

Inventory In July 2015, the FASB issued Accounting Standards Update No. 2015-11 (ASU 2015-11): *Simplifying the Measurement of Inventory*, effective for annual and interim periods beginning after December 15, 2016. ASU 2015-11 changes the inventory measurement principle for entities using the first-in, first out (FIFO) or average cost methods. For entities utilizing one of these methods, the inventory measurement principle will change from lower of cost or market to the lower of cost and net realizable value. We elected to early adopt this ASU as of December 31, 2016 and have applied the new measurement principle to our inventory balance. Adoption of this ASU did not have a material impact on our consolidated financial statements or related disclosures.

Revenue Recognition In May 2014, the FASB issued Accounting Standards Update No. 2014-09 (ASU 2014-09), which creates Topic 606, *Revenue from Contracts with Customers*. In summary, revenue recognition would occur upon the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Additionally, ASU 2014-09 requires enhanced financial statement disclosures over revenue recognition as part of the new accounting guidance. The standard will be effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. In March 2016, the FASB released certain implementation guidance through ASU 2016-08 to clarify principal versus agent considerations. Currently, we do not have any contracts that would require a change from the entitlements method, historically used for certain domestic natural gas sales, to the sales method of accounting. We are continuing to evaluate the provisions of this ASU as pertinent to certain sales contracts and in particular as it relates to disclosure requirements.

Investments - Equity Method and Joint Ventures In March 2016, the FASB issued Accounting Standards Update No. 2016-07 (ASU 2016-07): *Investments - Equity Method and Joint Ventures*, to eliminate retroactive application of equity method accounting when an investment becomes qualified for equity method accounting as a result of an increase in the level of ownership interest or degree of influence. The ASU will be effective for annual and interim periods beginning after December 15, 2016, with earlier application permitted. Based upon our evaluation, the adoption of this ASU will not have a material effect on our consolidated financial statements or related disclosures as all material investments are accounted for under the equity method of accounting.

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

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 certain cash receipts and cash payments should be presented in the statement of cash flows. Specifically, ASU 2016-15 provides additional guidance for certain cash flow items which may impact our presentation and classification within our statement of cash flows, including debt prepayments or debt extinguishment costs and distributions received from equity method investees. ASU 2016-15 will be effective for annual and interim periods beginning after December 15, 2017, with earlier application permitted. We do not believe adoption of ASU 2016-15 will have a material impact on our statement of cash flows and related disclosures as this update pertains to classification of items and is not a change in accounting principle.

Note 2. Additional Financial Statement Information

Additional statements of operations information is as follows:

	Year Ended December 31,		
(millions)	2016	2015	2014
Production Expense			
Lease Operating Expense	$ 542	$ 563	$ 593
Production and Ad Valorem Taxes	78	127	184
Transportation and Gathering Expense [1]	463	289	168
Total	$ 1,083	$ 979	$ 945
Exploration Expense			
Leasehold Impairment and Amortization [2]	148	113	43
Dry Hole Cost [2]	579	266	226
Seismic, Geological and Geophysical	76	34	86
Staff Expense	77	43	72
Other	45	32	71
Total	925	488	498
Other Operating (Income) Expense, Net			
Marketing Expense [3]	58	33	16
Loss on Terminated Contract [4]	41	—	—
Gain on Divestitures, Net [5]	(238)	—	(73)
Corporate Restructuring Expense [6]	8	51	—
Gain on Debt Extinguishment [7]	(80)	—	—
Pension Plan Expense [8]	—	88	—
Impact of Rosetta Merger [9]	(25)	81	—
Other, Net	70	96	49
Total	$ (166)	$ 349	$ (8)
Other Non-Operating (Income) Expense, Net			
Deferred Compensation Expense (Income) [10]	$ 11	$ (12)	$ (25)
Other (Income) Expense, Net	(2)	(3)	(1)
Total	$ 9	$ (15)	$ (26)

(1) Certain of our revenue received from purchasers was historically presented with deductions for transportation, gathering, fractionation or processing costs. Beginning in 2016, we have changed our presentation of revenue to no longer include these expenses as deductions from revenue. These costs are now included within production expense. Prior year amounts of $50 million and $14 million for the years ended December 31, 2015 and 2014, respectively, have been reclassified to transportation and gathering expense to conform to the current presentation.

(2) See Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

(3) Amounts represent expense for unutilized firm transportation and shortfalls in delivering or transporting minimum volumes under certain commitments. Prior year amounts of $33 million and $16 million for the years ended December 31, 2015 and 2014, respectively, were previously presented within transportation and gathering expense. These amounts have been reclassified to conform to the current presentation. See Note 18. Commitments and Contingencies.

(4) Amount relates to the termination of a rig contract offshore Falkland Islands as a result of a supplier's non-performance.

(5) Includes gain related to the sale of 3.5% working interest in the Tamar field, offshore Israel. See Note 3. Acquisitions, Divestitures and Merger.

(6) Amount represents expenses associated with organizational activities.

(7) Amount relates to the tendering of senior notes assumed in the Rosetta Merger. See Note 10. Long-Term Debt.
(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 3. Acquisitions, Divestitures and Merger.
(10) Amounts represent increases (decreases) in the fair values of shares of our common stock held in a rabbi trust and mutual funds.

Additional balance sheet information is as follows:

	December 31,	
(millions)	2016	2015
Accounts Receivable, Net		
Commodity Sales	$ 403	$ 298
Joint Interest Billings	106	20
Proceeds Receivable (1)	40	—
Other	86	151
Allowance for Doubtful Accounts	(20)	(19)
Total	$ 615	$ 450
Other Current Assets		
Inventories, Materials and Supplies	$ 71	$ 92
Inventories, Crude Oil	18	23
Assets Held for Sale(2)	18	67
Restricted Cash (3)	30	—
Prepaid Expenses and Other Assets, Current	23	34
Total	$ 160	$ 216
Other Noncurrent Assets		
Equity Method Investments	$ 400	$ 453
Mutual Fund Investments	71	90
Other Assets, Noncurrent	37	77
Total	$ 508	$ 620
Other Current Liabilities		
Production and Ad Valorem Taxes	$ 115	$ 166
Commodity Derivative Liabilities, Current	102	—
Income Taxes Payable	53	86
Asset Retirement Obligations, Current	160	128
Interest Payable	76	83
Current Portion of Capital Lease and Other Obligations	63	53
Other Liabilities, Current	173	161
Total	$ 742	$ 677
Other Noncurrent Liabilities		
Deferred Compensation Liabilities, Noncurrent	$ 218	$ 217
Asset Retirement Obligations, Noncurrent	775	861
Production and Ad Valorem Taxes	47	68
Other Liabilities, Noncurrent	63	73
Total	$ 1,103	$ 1,219

(1) Proceeds relate to our farm-out of a 35% interest in Block 12 offshore Cyprus and were received in January 2017. See Note 3. Acquisitions, Divestitures and Merger.

(2) Assets held for sale at December 31, 2016 included assets in the Greeley Crescent area of the DJ Basin. Assets held for sale at December 31, 2015 included the Karish and Tanin natural gas discoveries, offshore Israel. See Note 3. Acquisitions, Divestitures and Merger.

(3) Represents amount held in escrow at December 31, 2016 for the purchase of certain Permian Basin properties. See Note 3. Acquisitions, Divestitures and Merger.

Supplemental statements of cash flow information is as follows:

	Year Ended December 31,		
(millions)	2016	2015	2014
Cash Paid During the Year For			
Interest, Net of Amount Capitalized	$ 327	$ 260	$ 189
Income Taxes Paid, Net	236	202	150
Non-Cash Financing and Investing Activities			
Increase in Capital Lease and Other Obligations	5	55	110

Note 3. Acquisitions, Divestitures and Merger

Pending Acquisition of Clayton Williams Energy, Inc. On January 13, 2017 we executed a definitive agreement to acquire all of the outstanding common stock of Clayton Williams Energy, Inc. for $2.7 billion in Noble Energy stock and cash.

The transaction has been unanimously approved by the Boards of Directors of both Noble Energy and Clayton Williams Energy and is subject to approval by stockholders of Clayton Williams Energy. If approved, Clayton Williams Energy stockholders will receive 2.7874 shares of Noble Energy common stock and $34.75 in cash for each share of common stock held. In the aggregate, this totals 55 million shares of Noble Energy stock and $665 million in cash. The value of the transaction, based on Noble Energy's closing stock price as of January 13, 2017, is approximately $3.2 billion in the aggregate including the assumption of approximately $500 million in net debt. We intend to fund the cash portion of the acquisition through a draw on our Revolving Credit Facility.

Closing is expected to occur second quarter 2017 and is subject to customary regulatory approvals, approval by the holders of a majority of Clayton Williams Energy common stock, and certain other conditions.

Property Acquisition In fourth quarter 2016, we entered an agreement to purchase Permian Basis properties, including seven producing wells. The acquisition, which has a total transaction price of $295 million, will increase our contiguous acreage position in the Reeves County area. In December 2016, we paid initial consideration of $30 million into an escrow account, which is reflected as a restricted asset in our consolidated balance sheet. We paid the remaining consideration and completed the acquisition in January 2017.

Termination of Marcellus Shale JDA In fourth quarter 2016, we and 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. As a result, we now hold an almost 100% operated working interest in approximately 363,000 acres, primarily located in northwest West Virginia. 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. See Supplementary Data – Supplemental Oil and Gas Information (Unaudited), below, for discussion of proved reserves divested in connection with the transaction.

DJ 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.

Divestitures We maintain an ongoing portfolio management program. Accordingly, we may periodically divest assets or engage in acreage exchanges.

2016 Asset Sales 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. We expect to close the sale of the remaining properties, which are classified as held for sale at December 31, 2016, and receive the remaining proceeds, subject to post-close adjustments, in mid-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 onshore US 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, offshore Israel, which included the Karish and Tanin fields, 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 field, offshore Israel, in compliance with the terms of the Israel Natural Gas Framework, which requires us to reduce our ownership interest in Tamar 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 field's basis and resulted in the recognition of a $261 million gain.
- received proceeds of $131 million related to a farm-out agreement for a 35% interest in Block 12, offshore Cyprus, which includes the Aphrodite natural gas discovery. 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.

See Supplementary Data – Supplemental Oil and Gas Information (Unaudited), below, for discussion of proved reserves divested in connection with the above transactions.

2015 Asset Sales In 2015, we sold certain non-strategic onshore US properties, receiving proceeds of $151 million, with no gain or loss recorded.

*2014 Asset Sale*s In 2014, we sold certain non-strategic onshore US properties, receiving proceeds of $135 million, and recorded a net gain of $36 million. We also sold our China assets, receiving proceeds of $186 million, and recorded a gain of $35 million.

Aggregated information regarding assets sold is as follows:

	Year Ended December 31,		
(millions)	2016	2015	2014
Sales Proceeds	$ 1,241	$ 151	$ 321
Less			
Net Book Value of Assets Sold	(993)	(156)	(297)
Asset Retirement Obligations Associated with Assets Sold	7	8	48
Goodwill Allocated to Assets Sold	—	(4)	(7)
Other Closing Adjustments	(17)	1	8
Gain on Divestitures, Net	$ 238	$ —	$ 73

Rosetta Merger On July 20, 2015, Noble Energy completed the merger of Rosetta into a subsidiary of Noble Energy (Rosetta Merger). The results of Rosetta's operations since the merger date are included in our consolidated statement of operations. The merger was effected through the issuance of approximately 41 million shares of Noble Energy common stock in exchange for all outstanding shares of Rosetta using a ratio of 0.542 of a share of Noble Energy common stock for each share of Rosetta common stock and the assumption of Rosetta's liabilities, including approximately $2 billion fair value of outstanding debt.

The merger added two new onshore US shale positions to our portfolio including approximately 50,000 net acres in the Eagle Ford Shale and 54,000 net acres in the Permian Basin (45,000 acres in the Delaware Basin and 9,000 acres in the Midland Basin). In connection with the Rosetta Merger, we incurred merger-related costs 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 following table represents the final allocation of the total purchase price of Rosetta to the assets acquired and the liabilities assumed based on the fair values at the merger date, with any excess of the purchase price over the estimated fair values of the identifiable net assets acquired recorded as goodwill.

The following table sets forth our final purchase price allocation:

		(in millions, except stock price)
Shares of Noble Energy common stock issued to Rosetta shareholders		41
Noble Energy common stock price on July 20, 2015	$	36.97
Fair value of common stock issued	$	1,518
Plus: fair value of Rosetta's restricted stock awards and performance awards assumed		10
Plus: Rosetta stock options assumed		1
Total purchase price	$	1,529
Plus: liabilities assumed by Noble Energy		
Accounts Payable		100
Current Liabilities		37
Long-Term Debt		1,992
Other Long Term Liabilities		23
Asset Retirement Obligation		27
Total purchase price plus liabilities assumed	$	3,708
Fair Value of Rosetta Assets		
Cash and Equivalents	$	61
Other Current Assets		76
Derivative Instruments		209
Oil and Gas Properties:		
Proved Properties		1,613
Undeveloped Leaseholds		1,355
Gathering and Processing Assets		207
Asset Retirement Obligation		27
Other Property Plant and Equipment		5
Long Term Deferred Tax Asset		17
Implied Goodwill (1)		138
Total Asset Value	$	3,708

(1) As of December 31, 2015, our preliminary purchase price allocation reflected goodwill of $163 million based on the fair value of assets acquired and liabilities assumed at the Rosetta Merger date. In conducting our goodwill impairment test as of December 31, 2015, we determined that our goodwill balance was no longer recoverable and fully impaired it, resulting in a goodwill impairment charge in fourth quarter 2015. In second quarter 2016, we finalized the purchase price allocation and recorded a $25 million gain to other operating expense, net driven by adjustments made based on the filing of the final Rosetta federal income tax return for the period ending on the Rosetta Merger date.

The fair value measurements of derivative instruments assumed were determined based on published forward commodity price curves as of the date of the merger and represent Level 2 inputs. Derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. The fair value measurements of long-term debt were estimated based on published market prices and represent Level 1 inputs. The long-term debt balance includes amounts outstanding under Rosetta's credit facility which was assumed by Noble and repaid subsequent to the merger in third quarter 2015.

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

The results of operations attributable to Rosetta are included in our consolidated statement 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.

Pro Forma Financial Information The following pro forma condensed combined financial information was derived from the historical financial statements of Noble Energy and Rosetta and gives effect to the merger as if it had occurred on January 1, 2014. The below information reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including (i) Noble Energy's common stock and equity awards issued to convert Rosetta's outstanding shares of common stock and equity awards as of the closing date of the merger, (ii) adjustments to conform Rosetta's historical policy of accounting for its oil and natural gas properties from the full cost method to the successful efforts method of accounting, (iii) depletion of Rosetta's fair-valued proved oil and gas properties, and (iv) the estimated tax impacts of the pro forma adjustments. Additionally, pro forma earnings for the year ended December 31, 2015 were adjusted to exclude $81 million of merger-related costs incurred by Noble Energy and $37 million incurred by Rosetta. The pro forma results of operations do not include any cost savings or other synergies that may result from the Rosetta Merger or any estimated costs that have been or will be incurred by us to integrate the Rosetta assets.

The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the Rosetta Merger taken place on January 1, 2014; furthermore, the financial information is not intended to be a projection of future results.

	Year Ended December 31,		
(in millions, except per share amounts)	2016 [1]	2015	2014
Revenues	$ 3,491	$ 3,478	$ 6,126
Net (Loss) Income Attributable to Noble Energy	(998)	(2,393)	1,607
Earnings (Loss) Per Share			
Basic	$ (2.32)	$ (5.64)	$ 4.01
Diluted	(2.32)	(5.64)	3.94

(1) No pro forma adjustments were made for the period as Rosetta's operations are included in our consolidated historical results.

Note 4. Noble Midstream Partners LP

Noble Midstream Partners LP In December 2014, we formed Noble Midstream Partners LP, a growth-oriented Delaware master limited partnership, to own, operate, develop and acquire a wide range of domestic midstream infrastructure assets. Noble Midstream Partners' current areas of focus are in the DJ Basin in Colorado and in the Delaware Basin within the Permian Basin in Texas.

Initial Public Offering of Noble Midstream Partners LP On September 15, 2016, Noble Midstream Partners common units began trading on the New York Stock Exchange under the symbol "NBLX." On September 20, 2016, Noble Midstream Partners completed its public offering of 14,375,000 common units representing limited partner interests in Noble Midstream Partners, which included 1,875,000 common units issued pursuant to the underwriters' exercise of their option to purchase additional common units, at a price to the public of $22.50 per common unit ($21.21 per common unit, net of underwriting discounts).

In exchange for the contributed assets, Noble Energy received:

- 1,527,584 common units, representing a 4.8% limited partner interest in Noble Midstream Partners;
- 15,902,584 subordinated units, representing an approximate 50.0% limited partner interest in Noble Midstream Partners;
- incentive distribution rights in Noble Midstream Partners; and
- the right to receive a cash distribution from Noble Midstream Partners.

In addition and concurrent with the closing of the offering, the General Partner retained a non-economic general partnership interest in Noble Midstream Partners, which is not entitled to receive cash distributions.

Noble Midstream Partners generated net proceeds of $299 million from the issuance of common units to the public, after deducting the underwriting discount, structuring fees and estimated offering expenses of $24 million.

Note 5. Asset Impairments

Pre-tax (non-cash) asset impairment charges were as follows:

	Year Ended December 31,		
(millions)	2016	2015	2014
Onshore US	$ —	$ —	$ 42
Deepwater Gulf of Mexico	—	158	350
Israel	88	36	14
Equatorial Guinea	—	339	—
North Sea	—	—	94
Other International and Corporate	4	—	—
Total	$ 92	$ 533	$ 500

2016 Asset Impairments While the Leviathan development project was not formally sanctioned at December 31, 2016, in fourth quarter 2016, we selected the initial development concept for the first phase of development of the Leviathan natural gas project and wrote off $88 million associated with certain development concepts that were not selected.

2015 Asset Impairments During 2015, certain properties in the deepwater Gulf of Mexico, offshore Israel and offshore Equatorial Guinea 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 deepwater 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.

2014 Asset Impairments As a result of declining crude oil prices at the end of 2014, we recorded impairment charges of $250 million related to certain onshore US and deepwater Gulf of Mexico properties.

We also recorded impairment charges of $74 million for the South Raton development, deepwater Gulf of Mexico, due to mechanical issues; $51 million related to asset retirement obligation increases for certain properties in the deepwater Gulf of Mexico and offshore Israel; $31 million related to the reclassification of certain non-strategic properties as assets held for sale; and $94 million related to North Sea MacCulloch field abandonment.

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.

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)	2016	2015	2014
Capitalized Exploratory Well Costs, Beginning of Period	$ 1,353	$ 1,337	$ 1,301
Additions to Capitalized Exploratory Well Costs Pending Determination of Proved Reserves	84	123	316
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]	(1)	(19)	(196)
Capitalized Exploratory Well Costs Charged to Expense [3]	(525)	(88)	(84)
Capitalized Exploratory Well Costs, End of Period	$ 768	$ 1,353	$ 1,337

(1) The 2016 amount relates to our farm-down of a 35% interest in Block 12 offshore Cyprus to a new partner.

(2) The 2015 amount relates primarily to onshore US exploration activity.

The 2014 amount relates primarily to the Dantzler well (deepwater Gulf of Mexico), for which we sanctioned a development plan, and the Karish and Tanin wells (offshore Israel), which were reclassified to assets held for sale.

(3) Capitalized exploratory well costs charged to expense are included within exploration expense in our consolidated statements of operations.

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 our Silvergate exploratory well in the deepwater Gulf of Mexico. The well did not encounter commercial hydrocarbons and has been plugged and abandoned.

The 2015 amount relates primarily to northeast Nevada. After assessing its commercial viability in the current commodity price environment, we elected to discontinue our exploration efforts.

The 2014 amount relates to non-strategic onshore US exploratory well costs and the Scotia exploratory well (offshore Falkland Islands) which were determined to be non-commercial.

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)	2016	2015	2014
Exploratory Well Costs Capitalized for a Period of One Year or Less	$ 69	$ 95	$ 247
Exploratory Well Costs Capitalized for a Period Greater Than One Year Since Commencement of Drilling	699	1,258	1,090
Balance at End of Period	$ 768	$ 1,353	$ 1,337
Number of Projects with Exploratory Well Costs That Have Been Capitalized for a Period Greater Than One Year Since Commencement of Drilling	10	14	13

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, 2016:

Country/Project (millions)	Total	Suspended Since 2014 - 2015	Suspended Since 2012 - 2013	Suspended Since 2011 & Prior	Progress
Deepwater Gulf of Mexico					
Troubadour	52	5	47	—	Evaluating development scenarios for this 2013 natural gas discovery including subsea tieback to existing infrastructure.
Katmai	98	98	—	—	Evaluating development scenarios for this 2014 crude oil discovery. In second quarter 2016, drilling operations at the Katmai 2 appraisal well, located in Green Canyon Block 39, were temporarily abandoned as a result of encountering high pressure in the untested fault block. We are assessing plans to progress appraisal and are evaluating tie-back options.
Offshore Equatorial Guinea					
Felicita (Block O)	45	7	9	29	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)	22	3	5	14	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)	54	6	13	35	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 the governments of Equatorial Guinea and Cameroon to evaluate natural gas monetization options for both Yolanda (Equatorial Guinea) and YoYo discoveries.
Offshore Israel					
Leviathan	199	18	77	104	Our development plan was approved by the Government of Israel and we are engaged in natural gas marketing activities to meet both Israeli domestic and regional export demands. We anticipate near-term project sanction and commencement of development activities.
Leviathan-1 Deep	85	7	51	27	The well did not reach the target interval in 2012. We are developing future drilling plans to test this deep oil concept, which is held by the Leviathan Development and Production Leases.
Dalit	31	4	7	20	Our 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.
Offshore Cyprus					
Cyprus	89	12	54	23	During first quarter 2016, we received proceeds of $131 million from our 35% farm-down of interest with a partner in Block 12. In second quarter 2016, we submitted an updated development plan and 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.
Other					
Projects less than $20 million	24	23	—	1	Continuing to assess and evaluate wells.
Total	$ 699	$ 183	$ 263	$ 253	

Undeveloped Leasehold Costs Undeveloped leasehold costs as of December 31, 2016 totaled $2.2 billion, including $2.1 billion related to onshore US unproved properties, $105 million related to deepwater Gulf of Mexico unproved properties, and $32 million related to international unproved properties.

We evaluate our exploration opportunities as part of our periodic impairment review. If, based upon a change in exploration plans, availability of capital and suitable rig and drilling equipment, resource potential, comparative economics, changing regulations and/or other factors, an impairment is indicated, we record either (1) impairment expense related to individually significant leases or (2) a decrease in the valuation of our pool of individually insignificant leases.

During 2016, we completed our geological evaluation of certain deepwater Gulf of Mexico and offshore Falkland Islands leases and licenses and determined that several, representing $127 million of undeveloped leasehold cost, should be relinquished or exited. As a result, we recognized $93 million of undeveloped leasehold impairment expense and recorded a $34 million decrease in our valuation pool of individually insignificant leases.

Note 7. Equity Method Investments

Equity Method Investments Equity method investments are included in other noncurrent assets in the consolidated balance sheets, and our share of earnings is reported as income from equity method investees in the consolidated statements of operations. 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. Investments accounted for under the equity method consist primarily of the following:

- 50% interest in CONE Gathering LLC (CONE Gathering), which owns and operates natural gas gathering facilities servicing our properties in the Marcellus Shale;
- 33.5% interest in CONE Midstream Partners, LP (CONE Midstream), a public master limited partnership, which constructs, owns and operates natural gas gathering and other midstream energy assets in support of our Marcellus Shale activities;
- 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 processing plant in Equatorial Guinea.

CONE Midstream Dropdown Transaction In fourth quarter 2016, CONE Midstream, completed its first acquisition of midstream assets (dropdown) from CONE Gathering since its initial public offering in 2014. CONE Gathering subsequently distributed $70 million cash and additional CONE Midstream common units to us. We currently own 7,110,638 common units and 14,581,560 subordinated units of CONE Midstream.

Equity method investments are as follows:

	December 31,	
(millions)	2016	2015
Equity Method Investments		
CONE Investments[1]	$ 172	$ 214
AMPCO	120	120
Alba Plant	82	87
Other	26	32
Total Equity Method Investments	$ 400	$ 453

[1] CONE Investments include CONE Midstream and CONE Gathering.

Other At December 31, 2016, consolidated retained earnings included $95 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, 2016. 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)	2016	2015
Balance Sheet Information		
Current Assets	$ 313	$ 343
Noncurrent Assets	1,390	1,418
Current Liabilities	149	229
Noncurrent Liabilities	256	108

	Year Ended December 31,		
(millions)	2016	2015	2014
Statements of Operations Information			
Operating Revenues	$ 667	$ 645	$ 1,142
Operating Expenses	355	393	405
Operating Income	312	252	737
Other (Income) Net	(7)	(9)	(9)
Income Before Income Taxes	319	261	746
Income Tax Provision	60	46	172
Net Income	$ 259	$ 215	$ 574

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, 2016.

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, 2016, 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
1H17 [1]	Swaps	NYMEX WTI	6,000	$ 55.08	$ —	$ —	$ —
1H17 [1]	Two-Way Collars	NYMEX WTI	2,000	—	—	40.00	50.44
1H17 [1]	Swaps	Dated Brent	3,000	62.80	—	—	—
2H17 [1]	Call Option [2]	NYMEX WTI	3,000	—	—	—	60.12
2H17 [1]	Swaptions [3]	NYMEX WTI	3,000	50.05	—	—	—
2H17 [1]	Swaptions [3]	Dated Brent	3,000	62.80	—	—	—
2017	Three-Way Collars	NYMEX WTI	24,000	—	39.08	47.71	61.20
2017	Two-Way Collars	NYMEX WTI	7,000	—	—	40.00	53.29
2017	Swaps	NYMEX WTI	4,000	50.90	—	—	—
2017	Call Option [2]	NYMEX WTI	3,000	—	—	—	57.00
2017	Three-Way Collars	ICE Brent	2,000	—	43.00	50.00	63.15
2017	Three-Way Collars	Dated Brent	2,000	—	35.00	45.00	66.33
2018	Three-Way Collars	NYMEX WTI	5,000	—	43.00	50.00	68.50
2018	Swaps	NYMEX WTI	5,000	54.03	—	—	—
2018	Swaptions [3]	NYMEX WTI	3,000	56.10	—	—	—
2018	Three-Way Collars	Dated Brent	3,000	—	40.00	50.00	70.41

(1) We traditionally enter into a hedge contract term of one year. For 2017 we have entered into various derivative hedging arrangements with a contract term of six months resulting in non-uniform annual volumes and weighted average prices.

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

(3) We have entered into certain derivative contracts (swaptions), which give counterparties the option to extend with similar terms for an additional 6-month or 12-month period.

As of December 31, 2016, we had entered into the following natural gas derivative instruments:

				Swaps		Collars	
Settlement Period	Type of Contract	Index	MMBtu Per Day	Weighted Average Fixed Price	Weighted Average Short Put Price	Weighted Average Floor Price	Weighted Average Ceiling Price
1H17 (1)	Swaps	NYMEX HH	30,000	$ 2.92	$ —	$ —	$ —
2H17 (1)	Swaps	NYMEX HH	30,000	3.45	—	—	—
2H17 (1)	Swaptions (2)	NYMEX HH	30,000	2.92	—	—	—
2017	Three-Way Collars	NYMEX HH	210,000	—	2.54	2.96	3.62
2017	Swaps	NYMEX HH	110,000	3.16	—	—	—
2017	Two-Way Collars	NYMEX HH	70,000	—	—	2.93	3.32
2018	Three-Way Collars	NYMEX HH	70,000	—	2.50	2.80	3.76

(1) We traditionally enter into a hedge contract term of one year. For 2017 we have entered into various derivative hedging arrangements with a contract term of six months resulting in non-uniform annual volumes and weighted average prices.

(2) We have entered into certain derivative contracts (swaptions), which give counterparties the option to extend with similar terms for an additional 6-month or 12-month period.

Fair Value Amounts and Gains and Losses on Derivative Instruments The fair values of derivative instruments in our consolidated balance sheets were as follows:

Fair Value of Derivative Instruments

	Asset Derivative Instruments				Liability Derivative Instruments			
	December 31, 2016		December 31, 2015		December 31, 2016		December 31, 2015	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
(millions)								
Commodity Derivative Instruments	Current Assets	$ —	Current Assets	$ 582	Current Liabilities	$ 102	Current Liabilities	$ —
	Noncurrent Assets	—	Noncurrent Assets	10	Noncurrent Liabilities	14	Noncurrent Liabilities	—
Total		$ —		$ 592		$ 116		$ —

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

	Year Ended December 31,		
(millions)	2016	2015	2014
Cash (Received) Paid in Settlement of Commodity Derivative Instruments			
Crude Oil	$ (499)	$ (844)	$ (34)
Natural Gas	(70)	(147)	5
NGLs [1]	—	(18)	—
Total Cash Received in Settlement of Commodity Derivative Instruments	(569)	(1,009)	(29)
Non-cash Portion of Loss (Gain) on Commodity Derivative Instruments			
Crude Oil	582	423	(863)
Natural Gas	126	65	(84)
NGLs [1]	—	20	—
Total Non-cash Portion of Loss (Gain) on Commodity Derivative Instruments	708	508	(947)
Loss (Gain) on Commodity Derivative Instruments			
Crude Oil	83	(421)	(897)
Natural Gas	56	(82)	(79)
NGLs [1]	—	2	—
Total Loss (Gain) on Commodity Derivative Instruments	$ 139	$ (501)	$ (976)

[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 consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Changes in asset retirement obligations were as follows:

	Year Ended December 31,	
(millions)	2016	2015
Asset Retirement Obligations, Beginning Balance	$ 989	$ 751
Liabilities Incurred	21	67
Liabilities Settled	(120)	(38)
Revision of Estimate	(3)	166
Accretion Expense	48	43
Asset Retirement Obligations, Ending Balance	$ 935	$ 989

Year Ended December 31, 2016 Liabilities incurred were due to new wells and facilities placed into service for onshore US, deepwater 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 deepwater Gulf of Mexico properties, $49 million related to onshore US properties abandoned or sold, $5 million related to offshore Israel properties and $1 million related to the North Sea.

Year Ended December 31, 2015 Liabilities incurred were due to new wells and facilities and included $22 million for onshore US, $16 million for deepwater Gulf of Mexico and $29 million for properties acquired in the Rosetta Merger.

We settled liabilities of $23 million for the DJ Basin, $2 million for deepwater Gulf of Mexico and $13 million for the North Sea.

Revisions were primarily due to changes in estimated costs for future abandonment activities and acceleration of timing of abandonment and included $96 million for the DJ Basin, $48 million for Eastern Mediterranean, $35 million for deepwater Gulf of Mexico, and decreases of $10 million for Equatorial Guinea and $3 million for other onshore US developments.

Note 10. Long-Term Debt

Our debt consists of the following:

	December 31, 2016		December 31, 2015	
(millions, except percentages)	Debt	Interest Rate	Debt	Interest Rate
Revolving Credit Facility, due August 27, 2020	$ —	—	$ —	—
Noble Midstream Revolving Credit Facility, due September 20, 2021	—	—	—	—
Capital Lease and Other Obligations	375	—	403	—
Term Loan Facility, due January 6, 2019	550	2.01%	—	—
8.25% Senior Notes, due March 1, 2019	1,000	8.25%	1,000	8.25%
5.625% Senior Notes, due May 1, 2021 (1)	379	5.63%	693	5.63%
4.15% Senior Notes, due December 15, 2021	1,000	4.15%	1,000	4.15%
5.875% Senior Notes, due June 1, 2022 (1)	18	5.88%	597	5.88%
7.25% Senior Notes, due October 15, 2023	100	7.25%	100	7.25%
5.875% Senior Notes, due June 1, 2024 (1)	8	5.88%	499	5.88%
3.90% Senior Notes, due November 15, 2024	650	3.90%	650	3.90%
8.00% Senior Notes, due April 1, 2027	250	8.00%	250	8.00%
6.00% Senior Notes, due March 1, 2041	850	6.00%	850	6.00%
5.25% Senior Notes, due November 15, 2043	1,000	5.25%	1,000	5.25%
5.05% Senior Notes, due November 15, 2044	850	5.05%	850	5.05%
7.25% Senior Debentures, due August 1, 2097	84	7.25%	84	7.25%
Total	$ 7,114		$ 7,976	
Unamortized Discount	(23)		(24)	
Unamortized Premium (2)	17		113	
Unamortized Debt Issuance Costs	(34)		(36)	
Total Debt, Net of Discount	$ 7,074		$ 8,029	
Less Amounts Due Within One Year				
Capital Lease and Other Obligations	(63)		(53)	
Long-Term Debt Due After One Year	$ 7,011		$ 7,976	

(1) Represents senior notes assumed in the Rosetta Merger. See Note 3. Acquisitions, Divestitures and Merger.
(2) Debt premium is attributable to senior notes assumed in the Rosetta Merger.

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 On August 27, 2015, we amended our $4.0 billion Revolving Credit Facility to extend the maturity date to August 27, 2020. We periodically borrow amounts for working capital purposes.

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 Credit Agreement requires that our total debt to capitalization ratio (as defined in the Credit Agreement), 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, 2016, 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 Credit Agreement 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, a subsidiary of Noble Midstream Partners, entered into a credit agreement for a $350 million revolving credit facility (Noble Midstream Revolving Credit Facility). The Noble Midstream 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 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 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 LIBOR for an interest period of one month plus 1.00%; or
- in the case of London interbank offered rate (LIBOR) borrowings, the offered rate per annum for deposits of dollars for the applicable interest period.

The Noble Midstream 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 Revolving Credit Facility). All obligations of Noble Midstream Services, as the borrower under the Noble Midstream 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.

Term Loan Agreement and Completed Tender Offers On January 6, 2016, we entered into a term loan agreement (Term Loan Facility) with Citibank, N.A., as administrative agent, Mizuho Bank, Ltd., as syndication agent, and certain other financial institutions party thereto, which provides for a three-year term loan facility for a principal amount of $1.4 billion. Provisions of the Term Loan Facility are consistent with those in the Revolving Credit Facility. Borrowings under the Term Loan Facility may be prepaid prior to maturity without premium. The Term Loan Facility accrues interest, at our option, at either (a) a base rate equal to the highest of (i) the rate announced by Citibank, N.A., as its prime rate, (ii) the Federal Funds Rate plus 0.5%, and (iii) a LIBOR plus 1.0%, plus a margin that ranges from 10 basis points to 75 basis points depending upon our credit rating, or (b) a LIBOR, plus a margin that ranges from 100 basis points to 175 basis points depending upon our credit rating. The interest rate for our Term Loan Facility is 2.01% as of December 31, 2016.

In connection with the Term Loan Facility, we launched cash tender offers for the 5.875% Senior Notes due June 1, 2024, 5.875% Senior Notes due June 1, 2022 and 5.625% Senior Notes due May 1, 2021, all of which were assumed in the Rosetta Merger. The borrowings under the Term Loan Facility were used solely to fund the tender offers. Approximately $1.4 billion of notes were validly tendered and accepted by us, with a corresponding amount borrowed under the new Term Loan Facility. As a result, we recognized a gain of $80 million which is reflected in other operating (income) expense, net in our consolidated statements of operations.

In fourth quarter 2016, we prepaid $850 million of borrowings under our Term Loan Facility from cash on hand.

See Note 13. Fair Value Measurements and Disclosures for a discussion of methods and assumptions used to estimate the fair values of debt.

Debt Exchange On July 29, 2015, we completed our debt exchange offers to exchange all validly tendered and accepted senior notes assumed in the Rosetta Merger. We were able to exchange 99.4% of the outstanding Rosetta senior notes, whereby we issued (i) $693 million senior unsecured 5.625% notes due May 1, 2021, (ii) $597 million senior unsecured 5.875% notes due June 1, 2022 and (iii) $499 million senior unsecured 5.875% notes due June 1, 2024. We incurred financing costs of $12 million related to the debt exchange. We also repaid the balance outstanding under, and terminated, Rosetta's credit facility of $70 million.

Capital Lease and Other Obligations The amounts of the capital lease obligations are based on the discounted present value of future minimum lease payments, and therefore do not reflect future cash lease payments. Amounts due within one year equal the amount by which the capital lease obligations are expected to be reduced during the next 12 months. See Note 18. Commitments and Contingencies for future capital lease payments.

Annual Debt Maturities Annual maturities of outstanding debt, excluding capital lease payments, are as follows:

(millions)		Debt Principal Payments
December 31, 2016		
2017	$	—
2018		—
2019		1,550
2020		—
2021		1,379
Thereafter		3,810
Total	$	6,739

Note 11. Income Taxes

Components of income (loss) from operations before income taxes are as follows:

	Year Ended December 31,					
(millions)		2016		2015		2014
Domestic	$	(1,859)	$	(2,338)	$	282
Foreign		87		119		1,428
Total	$	(1,772)	$	(2,219)	$	1,710

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

	Year Ended December 31,					
(millions)		2016		2015		2014
Current Taxes						
Federal	$	(4)	$	(1)	$	19
State		5		—		1
Foreign		196		107		208
Total Current	$	197	$	106	$	228
Deferred Taxes						
Federal	$	(784)	$	216	$	237
State		(24)		(5)		13
Foreign		(176)		(95)		18
Total Deferred	$	(984)	$	116	$	268
Total Income Tax Provision (Benefit) Attributable to Noble Energy	$	(787)	$	222	$	496
Effective Tax Rate		44.4%		(10.0)%		29.0%

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Year Ended December 31,		
(percentages)	2016	2015	2014
Federal Statutory Rate	35.0%	35.0 %	35.0%
Effect of			
Earnings of Equity Method Investees	1.0	0.6	(3.3)
Noncontrolling Interests	0.4	—	—
Foreign Rate Change	1.6	—	—
State Taxes, Net of Federal Benefit	1.3	0.3	0.8
Difference Between US and Foreign Rates	(0.1)	2.6	(14.2)
Foreign Exploration Loss	0.1	2.7	—
Change in Valuation Allowance	(2.0)	—	1.9
Oil Profits Tax - Israel	—	0.1	0.2
Tax Contingency	0.2	0.4	0.1
Accumulated Undistributed Foreign Earnings	7.2	(37.7)	8.2
Goodwill Impairment	—	(12.3)	—
Other, Net	(0.3)	(1.7)	0.3
Effective Rate	44.4%	(10.0)%	29.0%

Deferred tax assets and liabilities resulted from the following:

	December 31,	
(millions)	2016	2015
Deferred Tax Assets		
Loss Carryforwards	$ 474	$ 468
Employee Compensation and Benefits	150	151
Other	49	81
Total Deferred Tax Assets	$ 673	$ 700
Valuation Allowance - Foreign Loss Carryforwards	(242)	(206)
Net Deferred Tax Assets	$ 431	$ 494
Deferred Tax Liabilities		
Mark to Market of Commodity Derivative Instruments	44	(128)
Accumulated Undistributed Foreign Earnings	(240)	(368)
Property, Plant and Equipment, Principally Due to Differences in Depreciation, Amortization, Lease Impairment and Abandonments	(2,054)	(2,824)
Total Deferred Tax Liability	$ (2,250)	$ (3,320)
Net Deferred Tax Liability	$ (1,819)	$ (2,826)

Net deferred tax liabilities were classified in the consolidated balance sheets as follows:

	December 31,	
(millions)	2016	2015
Deferred Income Tax Liability - Current	$ —	$ —
Deferred Income Tax Liability - Noncurrent	(1,819)	(2,826)
Net Deferred Tax Liability	$ (1,819)	$ (2,826)

Deferred Tax Assets 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, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, we believe it is more likely than not that we will realize the benefits of these deductible differences at December 31, 2016. 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.

The valuation allowance on the deferred tax assets associated with foreign loss carryforwards totaled $242 million in 2016 and $206 million in 2015. The changes to the valuation allowance for the loss carryforwards between periods were attributable to changes in losses on projects in new venture activities which are not yet commercial.

During 2015, as a result of cash repatriation, we released a valuation allowance of $60 million on our foreign tax credits.

Rosetta Merger On July 20, 2015, we completed the Rosetta Merger. For federal income tax purposes, the merger qualified as a tax free merger and we acquired carryover tax basis in Rosetta's assets and liabilities. Rosetta had a net deferred tax asset resulting from its federal net operating loss (NOL) estimated at $681 million through the date of acquisition. The merger resulted in a change of control for federal income tax purposes, and the NOL's usage will be subject to an annual limitation in part based on Rosetta's value at the date of the merger. We anticipate full utilization of the total NOL prior to its expiration.

Accumulated Undistributed Earnings of Foreign Subsidiaries Our foreign subsidiaries' undistributed earnings of approximately $1.6 billion at December 31, 2016 are no longer considered to be indefinitely reinvested outside the US and, during 2016, we recorded a $128 million deferred tax benefit to reduce the deferred tax liability recorded at the end of 2015, net of estimated foreign tax credits. 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. The actual tax impact upon distribution would depend on our tax positions at the time of repatriation and could be significantly different from this estimate.

Effective Tax Rate 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, as well as the 2015 impact of foreign dividend repatriation and goodwill impairment.

Our effective tax rate decreased in 2015 as compared with 2014 primarily due to a shift from pre-tax earnings in 2014 to a pre-tax loss in 2015 and the removal of our permanent reinvestment assertion discussed above. In the case of a pre-tax loss, our favorable permanent differences, such as income from equity method investees, have the effect of increasing the tax benefit which, in turn, increases the effective tax rate. Unfavorable permanent differences, such as non-deductible goodwill impairment expense, have the effect of decreasing the tax benefit which, in turn, decreases the effective tax rate. The decrease in the effective tax rate was partially offset by a release of the valuation allowance on foreign tax credits due to usage and losses from funding foreign exploration projects.

Changes in Israeli Tax Law Effective January 2016, the Israeli government decreased the corporate income tax rate from 26.5% to 25%, and in December 2016 announced a further rate decrease to 24% effective January 2017. The change decreased the deferred tax expense for 2016 by $30 million.

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 - 2013, Equatorial Guinea - 2011 and Israel - 2015.

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, 2016
Unrecognized Tax Benefits, Beginning Balance	$ 8
Additions for Tax Positions Related to Current Year	—
Additions for Tax Positions of Prior Years	—
Reductions for Tax Positions of Prior Years	(3)
Settlements	(2)
Unrecognized Tax Benefits, Ending Balance	$ 3

Unrecognized tax benefits which would impact our effective tax rate if recognized were approximately $3 million as of December 31, 2016. The changes to our unrecognized tax benefits during 2016 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 2016, we recognized and accrued a de minimis amount of interest and no penalties.

We expect that our unrecognized tax benefits will continue to change due to the settlement of audits and the expiration of statutes of limitation during the next twelve months; however, we do not anticipate any such change to have a significant impact on our results of operations, financial position or cash flows.

Note 12. Stock-Based and Other Compensation Plans

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,		
(millions)	2016	2015	2014
Stock-Based Compensation Expense Included in			
General and Administrative Expense	$ 62	$ 50	$ 63
Exploration Expense and Other	15	36	24
Total Stock-Based Compensation Expense	$ 77	$ 86	$ 87
Tax Benefit Recognized	$ (27)	$ (30)	$ (31)

Stock Option and Restricted Stock Plans Our stock option and restricted stock plans are described below.

1992 Stock Option and Restricted Stock Plan Under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended (the 1992 Plan), the Compensation, Benefits and Stock Option Committee of the Board of Directors (the Committee) may grant stock options and stock appreciation rights and award restricted stock and cash awards to our officers or other employees and those of our subsidiaries. The maximum number of shares that may be granted under the 1992 Plan is 77,400,000 shares of common stock. At December 31, 2016, 27,581,280 shares of our common stock were reserved for issuance, including 13,059,725 shares available for future grants and awards, under the 1992 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 1992 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 1992 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. Restricted stock awards with a performance-vested restriction 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, 2016, 705,615 shares of our common stock were reserved for issuance including 563,075 shares available for future grants and awards, under the 2015 Plan.

2005 Stock Plan for Non-Employee Directors The 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc., as amended (the 2005 Plan) provides for grants of stock options and awards of restricted stock to our non-employee directors. At December 31, 2016, 404,865 shares of our common stock were reserved for issuance in accordance with the 2005 Plan; however, the 2005 Plan was terminated in 2015, and no additional options can be granted thereunder. Options were issued with an exercise price equal to the market price of our common stock on the date of grant and may be exercised one year after the date of grant. Unless granted by the Board of Directors for a shorter term, the options expire 10 years from the date of grant.

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)	2016	2015	2014
Expected Term (in Years)	6.3	6.0	5.9
Expected Volatility	32.4%	32.6%	35.1%
Risk-Free Rate	1.6%	1.4%	1.8%
Expected Dividend Yield	0.7%	1.2%	1.1%
Weighted Average Grant-Date Fair Value	$ 10.10	$ 13.93	$ 20.31

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, 2015	14,571,012	$ 44.59		
Granted	2,441,042	31.66		
Exercised	(954,898)	25.96		
Forfeited	(968,294)	47.27		
Outstanding at December 31, 2016	15,088,862	$ 43.49	5.4	$ 40
Exercisable at December 31, 2016	10,999,318	$ 44.54	4.3	$ 26

The total intrinsic value of options exercised was $10 million in 2016, $7 million in 2015, and $58 million in 2014.

As of December 31, 2016, $26 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 U.S. 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,	
	2016	2015
Number of Simulations	500,000	500,000
Expected Volatility	38%	30%
Risk-Free Rate	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, 2015	1,019,470	$ 45.55	1,929,922	$ 28.50
Awarded	898,916	31.67	363,256	24.80
Vested	(421,227)	52.50	(340,410)	42.71
Forfeited	(125,379)	35.54	(449,776)	37.86
Outstanding at December 31, 2016	1,371,780	$ 36.37	1,502,992	$ 27.43

The total fair value of restricted stock that vested was $24 million in 2016, $62 million in 2015, and $50 million in 2014.

The weighted average award-date fair value of restricted stock awarded was $29.99 per share in 2016, $35.53 per share in 2015, and $41.22 per share in 2014.

As of December 31, 2016, $32 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 1.3 years 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 based on the assumptions below.

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, 2016, we had accrued a liability of $9 million related to the phantom units.

The assumptions used in valuing market based phantom units awarded were as follows:

	Year Ended December 31,
	2016
Number of Simulations	500,000
Expected Volatility	38%
Risk-Free Rate	0.9%

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, 2015	—	$ —	—	$ —
Awarded	791,000	31.65	218,180	6.82
Vested	(2,501)	31.65	—	—
Forfeited	(76,410)	31.65	(8,676)	6.82
Outstanding at December 31, 2016	712,089	$ 31.65	209,504	$ 6.82

As of December 31, 2016, $18 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 2.0 years. The total fair value of phantom units that vested in 2016 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 $32 million in 2016, $35 million in 2015, and $26 million in 2014.

As a result of the termination of the pension plan, employees who were hired prior to May 1, 2006 became eligible to receive profit sharing contributions effective January 1, 2014. In addition, certain of these employees are eligible to receive transition contributions related to the termination of the plan.

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)	2016	2015
Rabbi Trust Assets		
Mutual Fund Investments	$ 62	$ 63
Noble Energy Common Stock (at Fair Value)	26	35
Total Rabbi Trust Assets	$ 88	$ 98
Liability Under Related Deferred Compensation Plan	$ 88	$ 98
Number of Shares of Noble Energy Common Stock Held by Rabbi Trust	671,269	872,277

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 600,000 shares, or 89%, of our common stock held in respect of one nonqualified deferred compensation plan at December 31, 2016 were attributable to a member of our Board of Directors. The shares are being distributed in equal installments over the next three years. Distributions of 200,000 shares were made in 2016, 200,000 shares in 2015 and 200,000 shares in 2014. In addition, plan participants sold 1,009 shares of our common stock in 2016, 1,009 shares in 2015, and 19,049 shares in 2014. Proceeds were invested in mutual funds and/or distributed to plan participants. Distributions to plan participants were valued at $22 million in 2016, $18 million in 2015 and $22 million in 2014.

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 $11 million in 2016, $(12) million in 2015 and $(25) million in 2014.

We also maintain other nonqualified deferred compensation plans for the benefit of certain of our employees. Deferred compensation liabilities of $121 million and $119 million were outstanding at December 31, 2016 and 2015, 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 sheet. The following methods and assumptions were used to estimate the fair values:

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

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

Commodity Derivative Instruments Our commodity derivative instruments may include variable to fixed price commodity swaps, two-way collars, three-way collars, swaptions and extendable/enhanced swaps. We estimate the fair values of these instruments using published forward commodity price curves as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk, and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. In addition, for collars, we estimate the option values of the put options sold and the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. See Note 8. Derivative Instruments and Hedging Activities.

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.

Deferred Compensation Liability The value is dependent upon the fair values of mutual fund investments and shares of our common stock held in a rabbi trust. See *Mutual Fund Investments* above.

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

	Fair Value Measurements Using				
(millions)	Quoted Prices in Active Markets (Level 1) [1]	Significant Other Observable Inputs (Level 2) [1]	Significant Unobservable Inputs (Level 3) [1]	Adjustment [2]	Fair Value Measurement
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)
December 31, 2015					
Financial Assets					
Mutual Fund Investments	$ 90	$ —	$ —	$ —	$ 90
Commodity Derivative Instruments	—	600		(8)	592
Financial Liabilities					
Commodity Derivative Instruments	—	(8)	—	8	—
Portion of Deferred Compensation Liability Measured at Fair Value	(98)	—	—	—	(98)

(1) 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 2016, 2015 and 2014, 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.

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, 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
Year Ended December 31, 2014					
Impaired Oil and Gas Properties	—	—	100	600	500

(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 the 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 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. 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.

Our Term Loan Facility is variable-rate, non-public debt. The carrying amount of floating-rate debt approximates fair value as the interest rates are variable and reflective of market rates. See Note 10. Long-Term Debt.

Fair value information regarding our debt is as follows:

	December 31, 2016		December 31, 2015	
(millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt, Net [1]	$ 6,699	$ 7,112	$ 7,626	$ 7,105

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

Note 14. Earnings (Loss) Per Share Attributable to Noble Energy

Noble Energy's basic earnings (loss) per share of common stock is computed by using net income (loss) attributable to Noble Energy divided by the weighted average number of shares of Noble Energy common stock outstanding during each period. The diluted earnings (loss) per share of common stock includes the effect of outstanding stock options, shares of restricted stock, or shares of our common stock held in a rabbi trust (when dilutive). The following table summarizes the calculation of basic and diluted earnings (loss) per share:

	Year Ended December 31,		
(millions, except per share amounts)	2016	2015	2014
Net Income (Loss) Attributable to Noble Energy	$ (998)	$ (2,441)	$ 1,214
Earnings Adjustment from Assumed Conversion of Dilutive Shares of Common Stock in Rabbi Trust [1]	—	—	(17)
Net Income (Loss) Used for Diluted Earnings (Loss) Per Share Calculation	$ (998)	$ (2,441)	$ 1,197
Weighted Average Number of Shares Outstanding, Basic[2]	430	402	361
Incremental Shares From Assumed Conversion of Dilutive Stock Options, Restricted Stock, and Shares of Common Stock in Rabbi Trust[1]	—	—	6
Weighted Average Number of Shares Outstanding, Diluted	430	402	367
Earnings (Loss) Attributable to Noble Energy Per Share, Basic	**$ (2.32)**	**$ (6.07)**	**$ 3.36**
Earnings (Loss) Attributable to Noble Energy Per Share, Diluted	**(2.32)**	**(6.07)**	**3.27**
Additional Information			
Number of antidilutive stock options, shares of restricted stock and shares of common stock in rabbi trust excluded from calculation above	14	10	3
Weighted average option exercise price per share	$ 45.69	$ 52.39	$ 60.30

(1) For the years ended December 31, 2016 and 2015, 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.

Consistent with GAAP, when dilutive, deferred compensation gains or losses, net of tax, are excluded from net income while our common shares held in the rabbi trust are included in the diluted share count. For this reason, the diluted earnings (loss) per share calculation for the year ended December 31, 2014 excludes deferred compensation gains, net of tax.

(2) The weighted average number of shares outstanding for the year ended December 31, 2015 includes the weighted average shares of common stock issued in connection with the underwritten public offering of 24.15 million shares of Noble Energy common stock in first quarter 2015 and issued in connection with the exchange of approximately 41 million shares for all outstanding shares of Rosetta common stock on July 20, 2015.

Note 15. Segment Information

We have operations throughout the world and manage our operations by region. The following information is grouped into four components that are all primarily in the business of crude oil, natural gas and NGL exploration, development, production and acquisition: the United States (which includes consolidated accounts of Noble Midstream Partners); West Africa (Equatorial Guinea, Cameroon, Gabon and Sierra Leone (which we exited in second quarter 2015)); Eastern Mediterranean (Israel and Cyprus); and Other International and Corporate. Other International includes the Falkland Islands, Suriname, the North Sea, China (through June 2014), Nicaragua (which we exited first quarter 2015) and new ventures. Net income (loss) before income taxes for the US and West Africa includes gains and losses on commodity derivative instruments.

	Consolidated	United States	Eastern Mediter-ranean	West Africa	Other Int'l & Corporate
Year Ended December 31, 2016					
Revenues from Third Parties [1]	$ 3,389	$ 2,416	$ 540	$ 433	$ —
Income from Equity Method Investees	102	52	—	50	—
Total Revenues	3,491	2,468	540	483	—
Exploration Expense	925	245	34	483	163
DD&A	2,454	2,122	81	205	46
Asset Impairments	92	—	88	—	4
Loss on Commodity Derivative Instruments	139	126	—	13	—
Income (Loss) Before Income Taxes	(1,772)	(1,052)	543	(338)	(925)
Equity Method Investments	400	183	—	217	—
Additions to Long-Lived Assets	1,526	1,359	88	54	25
Total Assets at End of Year [2]	21,011	17,029	2,233	1,479	270
Year Ended December 31, 2015					
Revenues from Third Parties [1]	$ 3,093	$ 2,011	$ 497	$ 580	$ 5
Income from Equity Method Investees	90	51	—	39	—
Total Revenues	3,183	2,062	497	619	5
Exploration Expense	488	203	12	46	227
DD&A	2,131	1,692	70	326	43
Asset Impairments	533	158	36	339	—
Goodwill Impairment	779	779	—	—	—
Gain on Commodity Derivative Instruments	(501)	(347)	—	(154)	—
Income (Loss) Before Income Taxes	(2,219)	(1,553)	306	(77)	(895)
Equity Method Investments	453	226	—	227	—
Additions to Long-Lived Assets	3,062	2,534	147	124	257
Goodwill at End of Year [3]	—	—	—	—	—
Total Assets at End of Year [2]	24,196	18,831	2,677	2,299	389
Year Ended December 31, 2014					
Revenues from Third Parties [1]	$ 4,945	$ 3,189	$ 479	$ 1,177	$ 100
Income from Equity Method Investees	170	9	—	161	—
Total Revenues	5,115	3,198	479	1,338	100
Exploration Expense	498	268	17	26	187
DD&A	1,759	1,318	63	299	79
Asset Impairments	500	392	14	—	94
Gain on Divestitures	(73)	(34)	—	—	(39)
Loss on Commodity Derivative Instruments	(976)	(604)	—	(372)	—
Income (Loss) Before Income Taxes	1,710	1,150	284	1,222	(946)
Equity Method Investments	325	82	—	223	20
Additions to Long-Lived Assets	5,152	4,389	201	261	301
Goodwill at End of Year [3]	620	620	—	—	—
Total Assets at End of Year [2]	22,518	16,365	2,806	2,763	584

(1) Revenues from third parties for all foreign countries, in total, were $973 million in 2016, $1.1 billion in 2015 and $1.8 billion 2014.

(2) Long-lived assets located in all foreign countries, in total, were $3.0 billion, $3.9 billion, and $4.4 billion at December 31, 2016, 2015, and 2014, respectively.

(3) As of December 31, 2015, our goodwill was fully impaired. See Note 1. Summary of Significant Accounting Policies.

Note 16. 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, 2016		
Glencore Energy UK Ltd	22%	12%
Shell [1]	24%	13%
Year Ended December 31, 2015		
Glencore Energy UK Ltd	30%	18%
Shell [1]	18%	11%
Year Ended December 31, 2014		
Glencore Energy UK Ltd	32%	22%
Shell [1]	15%	10%

[1] 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, natural gas and NGL 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, 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 our 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 17. Additional Shareholders' Equity Information

Activity in shares of our common stock and treasury stock was as follows:

	Year Ended December 31,	
	2016	2015
Common Stock Shares Issued		
Shares, Beginning of Period	469,718,512	402,329,325
Exercise of Common Stock Options	954,898	343,145
Restricted Stock Awards, Net of Forfeitures	687,017	1,847,802
Public Equity Offering	—	24,150,000
Shares Exchanged in Rosetta Merger	—	41,048,240
Shares, End of Period	471,360,427	469,718,512
Treasury Stock		
Shares, Beginning of Period	37,925,625	37,635,890
Shares Received From Employees in Payment of Withholding Taxes Due on Vesting of Shares of Restricted Stock	236,700	490,744
Rabbi Trust Shares Distributed and/or Sold	(201,009)	(201,009)
Shares, End of Period	37,961,316	37,925,625

Equity Offering On March 3, 2015, we closed an underwritten public offering of 21 million shares of common stock, par value $0.01 per share, at a price of $47.50 per share. In addition, on March 25, 2015, we completed the issuance of an additional 3.15 million shares of common stock, par value $0.01 per share, in connection with the exercise of the option of the underwriters to purchase additional shares of common stock. The aggregate net proceeds of the offerings were approximately $1.1 billion (after deducting underwriting discounts and commissions and offering expenses).

We used approximately $150 million of the net proceeds to repay outstanding indebtedness under our Revolving Credit Facility, which had been drawn for short-term purposes on February 27, 2015. The remainder of the net proceeds was used for general corporate purposes, including the funding of our capital investment program.

In accordance with our accounting policy, we excluded the intra-quarter Revolving Credit Facility activity from gross presentation in our consolidated statements of cash flows. We use net presentation when such activity includes short maturities (i.e., less than 90 days) with quick turnover.

Accumulated Other Comprehensive Loss Accumulated other comprehensive loss 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, 2013	$ (24)	$ (93)	$ (117)
Realized Amounts Reclassified Into Earnings	1	11	12
Unrealized Change in Fair Value	—	15	15
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)

All amounts in the table above are reported net of tax, using an effective income tax rate of 35%.

AOCL at December 31, 2016 included deferred losses of $21 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 18. 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 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.

The Consent Decree, which alleges violations of the Colorado Air Pollution Prevention and Control Act and Colorado's federal approved State Implementation Plan, specifically Colorado Air Quality Control Commission Regulation Number 7, requires us to perform certain injunctive relief activities to complete mitigation projects and supplemental environmental projects (SEP), and pay a civil penalty. Costs associated with the settlement consist of $4.95 million in civil penalties which were paid in 2015. Mitigation costs of $4.5 million and SEP costs of $4 million are being expended in accordance with schedules established in the Consent Decree. Costs associated with the injunctive relief are also being expended in accordance with schedules established in the Consent Decree. During 2015 and 2016, we spent approximately $54.7 million to undertake injunctive relief at certain tank systems following the outcome of adequacy of design evaluations and certain operation and maintenance activities to handle potential peak instantaneous vapor flow rates. Future costs associated with injunctive relief are not yet precisely quantifiable as we are continually evaluating various approaches to meet the ongoing obligations of the Consent Decree.

Overall compliance with the Consent Decree has resulted in the temporary shut-in and permanent plugging and abandonment of certain wells and associated tank batteries. Consent Decree compliance could result in additional temporary shut-ins and permanent plugging and abandonment of certain wells and associated tank batteries. The Consent Decree sets forth a detailed compliance schedule with deadlines for achievement of milestones through early 2019 that may be extended depending on certain situations. The Consent Decree contains additional obligations for ongoing inspection and monitoring beyond that which is required under existing Colorado regulations.

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

Colorado Air Compliance Order on Consent In December 2015, we received a proposed Compliance Order on Consent from the Colorado Department of Public Health and Environment's Air Pollution Control Division (APCD) to resolve allegations of noncompliance associated with certain engines subject to various General Permit 02 conditions and/or individual permit conditions as well as certain emission control devices subject to various individual permit conditions that applied to assets currently owned and operated by both Noble Energy and Noble Midstream Services, LLC. In May 2016, Noble Energy on behalf of itself and its wholly owned subsidiary Noble Midstream Services, LLC, on behalf of itself and its wholly owned subsidiary Colorado River DevCo LP, reached a final resolution with the APCD, which requires completion of compliance testing, modification of certain permits, payment of a civil penalty of $44,695, and an expenditure of no less than $178,780 on an approved SEP. 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 We have 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 one to 32 years, is approximately $2.1 billion, undiscounted. The agreements for firm transportation relate to services on new pipeline projects to be constructed by, and connecting to, existing and new interstate pipeline systems. The pipeline projects are expected to be complete and operational in 2017 and 2018. The commitment is included in the table below.

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 12 years, is approximately $850 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 $76 million in 2016, $84 million in 2015, and $69 million in 2014.

Minimum commitments as of December 31, 2016 consist of the following:

(millions)	Drilling, Equipment, and Purchase Obligations	Transportation and Gathering Obligations	Operating Lease Obligations	Capital Lease and Other Obligations (1)	Total
2017	$ 255	$ 250	$ 30	$ 77	$ 612
2018	96	312	42	79	529
2019	52	314	30	52	448
2020	27	275	28	52	382
2021	9	237	28	38	312
2022 and Thereafter	30	1,566	188	163	1,947
Total	$ 469	$ 2,954	$ 346	$ 461	$ 4,230

(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, natural gas and NGL reserves and exploration and production activities.

Reserves There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGL reserves. Crude oil, natural gas and NGL 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, natural gas and NGLs that are ultimately recovered.

Economic producibility of reserves is dependent on the crude oil, natural gas and NGL prices used in the reserves estimate. We based our December 31, 2016, 2015, and 2014 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, natural gas or NGL 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 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 members of senior 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, 2016. 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 Proved 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 natural gas, natural gas liquids and crude oil 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	Other Int'l [1]	Total
Proved Reserves as of:				
December 31, 2013	236	77	9	322
Revisions of Previous Estimates [2]	(5)	1	—	(4)
Extensions, Discoveries and Other Additions [3]	30	—	—	30
Purchase of Minerals in Place [4]	—	—	—	—
Sale of Minerals in Place [5]	—	—	(5)	(5)
Production [6]	(25)	(13)	(1)	(39)
December 31, 2014	236	65	3	304
Revisions of Previous Estimates [2]	(56)	(5)	—	(61)
Extensions, Discoveries and Other Additions [3]	42	—	—	42
Purchase of Minerals in Place [4]	65	—	—	65
Sale of Minerals in Place [5]	(2)	—	—	(2)
Production [6]	(29)	(12)	—	(41)
December 31, 2015	256	48	3	307
Revisions of Previous Estimates [2]	14	(4)	—	10
Extensions, Discoveries and Other Additions [3]	66	—	—	66
Purchase of Minerals in Place [4]	—	—	—	—
Sale of Minerals in Place [5]	(4)	—	—	(4)
Production [6]	(36)	(10)	—	(46)
December 31, 2016	296	34	3	333
Proved Developed Reserves as of				
December 31, 2013	102	64	8	174
December 31, 2014	119	52	3	174
December 31, 2015	137	34	3	174
December 31, 2016	138	34	3	175
Proved Undeveloped Reserves as of				
December 31, 2013	134	12	2	148
December 31, 2014	117	13	—	130
December 31, 2015	119	14	—	133
December 31, 2016	158	—	—	158

(1) Other International includes China (through June 2014), the North Sea (through 2014) and Israel.

(2) The 2014 US revisions were primarily associated with positive performance revisions to our Marcellus Shale program and our deepwater Gulf of Mexico Swordfish field, offset by DJ Basin negative revisions due to a revised drilling plan in response to the current commodity price environment.

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, offset by positive revisions of 14 MMBbls due to producing well performance and optimized lateral lengths in the Permian 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, Permian Basin and deepwater 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.

(3) The 2014 increase in US reserves included an increase of 21 MMBbls in the DJ Basin and 2 MMBbls from Marcellus Shale development as well as 7 MMBbls in the deepwater Gulf of Mexico due to sanction of the Dantzler development project.

The 2015 increase in US reserves was attributable to DJ Basin development.

The 2016 increase in US reserves primarily includes 38 MMBbls in the DJ Basin and 28 MMBbls in the Permian Basin and Eagle Ford Shale, and was associated with increased performance from our horizontal drilling programs.

(4) The 2015 increase is attributable to reserves acquired in the Rosetta Merger.

(5) In 2014, we sold our China assets.

In 2015, we sold onshore US assets.

In 2016, we sold onshore US assets.

(6) Equatorial Guinea production includes sales from the Alba LPG plant of approximately 3 MMBbl in each of the years 2016, 2015, and 2014.

See Items 1. and 2. Business and Properties – Proved Undeveloped Reserves (PUDs) and Note 3. 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	Other Int'l (2)	Total
Proved Reserves as of:					
December 31, 2013	2,656	2,479	691	2	5,828
Revisions of Previous Estimates (3)	58	21	11	—	90
Extensions, Discoveries and Other Additions (4)	433	—	—	—	433
Purchase of Minerals in Place (5)	—	—	—	—	—
Sale of Minerals in Place (6)	(154)	—	—	(2)	(156)
Production	(189)	(84)	(89)	—	(362)
December 31, 2014	2,804	2,416	613	—	5,833
Revisions of Previous Estimates (3)	(705)	(20)	4	—	(721)
Extensions, Discoveries and Other Additions (4)	257	—	—	—	257
Purchase of Minerals in Place (5)	629	—	—	—	629
Sale of Minerals in Place (6)	(16)	—	—	—	(16)
Production	(258)	(92)	(83)	—	(433)
December 31, 2015	2,711	2,304	534	—	5,549
Revisions of Previous Estimates (3)	181	(3)	38	—	216
Extensions, Discoveries and Other Additions (4)	492	—	—	—	492
Purchase of Minerals in Place (5)	—	—	—	—	—
Sale of Minerals in Place (6)	(224)	(214)	—	—	(438)
Production	(322)	(103)	(86)	—	(511)
December 31, 2016	2,838	1,984	486	—	5,308
Proved Developed Reserves as of					
December 31, 2013	1,212	2,046	457	2	3,717
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
Proved Undeveloped Reserves as of					
December 31, 2013	1,444	433	234	—	2,111
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

(1) In accordance with the terms of the Israel Natural Gas Framework, we are required to reduce our ownership in the Tamar field to 25% by year-end 2021. During 2016, we reduced our ownership to 32.5% through a sale.

(2) Other International includes China.

(3) The 2014 US revisions were primarily associated with a positive performance revision to our Marcellus Shale program offset by a negative revision to our DJ Basin program due to a revised drilling program in response to the current commodity price environment. Equatorial Guinea revisions are associated with positive performance revisions to the Alba field. Israel revisions are primarily associated with positive performance revisions to the Tamar field.

The 2015 US revisions are 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 are associated with positive performance revisions to the Alba field. Israel revisions are 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 are associated with positive performance revisions of 58 Bcf at the Alba field, partially offset by negative commodity price revisions of 20 Bcf.

(4) The 2014 increase in US reserves included an increase of 110 Bcf in the DJ Basin and 309 Bcf from Marcellus Shale development as well as 14 Bcf in the deepwater Gulf of Mexico.

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 Permian Basin and Eagle Ford Shale.

(5) The 2015 increase is attributable to reserves acquired in the Rosetta Merger.

(6) In 2014, we sold onshore US and China assets.

In 2015, we sold onshore US assets in the DJ Basin.

In 2016, we sold onshore US 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.

See Items 1. and 2. Business and Properties – Proved Undeveloped Reserves (PUDs) and Note 3. 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, 2013	95	18	113
Revisions of Previous Estimates	7	—	7
Extensions, Discoveries and Other Additions [2]	18	—	18
Purchase of Minerals in Place	—	—	—
Sale of Minerals in Place	—	—	—
Production [3]	(7)	(3)	(10)
December 31, 2014	113	15	128
Revisions of Previous Estimates	(37)	—	(37)
Extensions, Discoveries and Other Additions [2]	15	—	15
Purchase of Minerals in Place	100	—	100
Sale of Minerals in Place	(1)	—	(1)
Production [3]	(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	—	4
Sale of Minerals in Place	—	—	—
Production [3]	(20)	(2)	(22)
December 31, 2016	207	12	219
Proved Developed Reserves as of			
December 31, 2013	44	11	55
December 31, 2014	64	8	72
December 31, 2015	101	5	106
December 31, 2016	113	12	125
Proved Undeveloped Reserves as of			
December 31, 2013	51	7	58
December 31, 2014	49	7	56
December 31, 2015	75	8	83
December 31, 2016	94	—	94

(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, 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.

(2) The 2014 additions in US reserves included an increase of 8 MMBbls in the DJ Basin and 8 MMBbls from Marcellus Shale development.

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 Permian Basin and Eagle Ford shale due to improved well performance and/or decreases in development or operating costs.

(3) Equatorial Guinea production represents sale from the Alba LPG plant.

(4) The 2015 increase was attributable to reserves acquired in the Rosetta Merger.

The 2016 increase was attributable to the acreage exchange in the Marcellus Shale.

See Items 1. and 2. Business and Properties – Proved Undeveloped Reserves (PUDs) and Note 3. Acquisitions, Divestitures and Merger.

Results of Operations for Oil and Gas Producing Activities (Unaudited) Aggregate results of operations for crude oil and natural gas producing activities are as follows:

(millions)	United States	Israel	Equatorial Guinea	Other Int'l [1]	Total
Year Ended December 31, 2016					
Revenues	$ 2,416	$ 540	$ 433	$ —	$ 3,389
Production Costs [2]	992	49	118	3	1,162
Exploration Expense [3]	245	26	469	185	925
DD&A	2,122	81	205	46	2,454
Asset Impairments [4]	—	88	—	4	92
(Loss) Income before Income Taxes	(943)	296	(359)	(238)	(1,244)
Income Tax Expense (Benefit) [5]	(330)	74	(90)	—	(346)
Results of Operations [6]	$ (613)	$ 222	$ (269)	$ (238)	$ (898)
Year Ended December 31, 2015					
Revenues	$ 2,011	$ 497	$ 580	$ 5	$ 3,093
Production Costs [2]	817	67	145	15	1,044
Exploration Expense	202	6	1	279	488
DD&A	1,692	70	326	43	2,131
Asset Impairments [4]	158	36	339	—	533
(Loss) Income before Income Taxes	(858)	318	(231)	(332)	(1,103)
Income Tax Expense (Benefit) [5]	(300)	84	(58)	(5)	(279)
Results of Operations [6]	$ (558)	$ 234	$ (173)	$ (327)	$ (824)
Year Ended December 31, 2014					
Revenues	$ 3,189	$ 479	$ 1,177	$ 100	$ 4,945
Production Costs [2]	686	54	147	69	956
Exploration Expense	268	4	18	208	498
DD&A	1,318	63	299	79	1,759
Asset Impairments [4]	392	14	—	94	500
Income (Loss) before Income Taxes	525	344	713	(350)	1,232
Income Tax Expense [5]	184	94	178	18	474
Results of Operations [6]	$ 341	$ 250	$ 535	$ (368)	$ 758

(1) Other International includes the North Sea (through 2014), China (through June 30, 2014) and new ventures.

(2) 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.

(3) Equatorial Guinea exploration expense includes $468 million for the write off of costs associated with certain discoveries. See Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs.

(4) Asset impairments relate to certain Leviathan development concepts costs. See Note 5. Asset Impairments.

(5) Income tax expense is based upon respective corporate statutory tax rates. During 2016, 2015, and 2014, 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.

(6) 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.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (Unaudited) [1]

Costs incurred in connection with crude oil and natural gas acquisition, exploration and development are as follows:

	United States	Israel	Equatorial Guinea	Other Int'l [2]	Total
(millions)					
Year Ended December 31, 2016					
Property Acquisition Costs					
Proved [3]	$ —	$ —	$ —	$ —	$ —
Unproved [3]	234	—	—	—	234
Exploration Costs [4]	264	26	25	44	359
Development Costs [5]	939	109	31	—	1,079
Total Consolidated Operations	$ 1,437	$ 135	$ 56	$ 44	$ 1,672
Company's Share of CONE Gathering Development Costs	$ 8	$ —	$ —	$ —	$ 8
Year Ended December 31, 2015					
Property Acquisition Costs					
Proved [3]	$ 1,613	$ —	$ —	$ —	$ 1,613
Unproved [3]	1,478	—	—	2	1,480
Exploration Costs [4]	206	22	22	234	484
Development Costs [5]	2,455	104	75	10	2,644
Total Consolidated Operations	$ 5,752	$ 126	$ 97	$ 246	$ 6,221
Company's Share of CONE Gathering Development Costs	$ 104	$ —	$ —	$ —	$ 104
Year Ended December 31, 2014					
Property Acquisition Costs					
Unproved [3]	$ 246	$ —	$ —	$ 3	$ 249
Exploration Costs [4]	485	60	61	64	670
Development Costs [5]	3,685	144	211	78	4,118
Total Consolidated Operations	$ 4,416	$ 204	$ 272	$ 145	$ 5,037
Company's Share of CONE Gathering Development Costs	$ 71	$ —	$ —	$ —	$ 71

(1) Costs incurred include capitalized and expensed items.

(2) Other International includes the North Sea, China (through June 30, 2014) and new ventures. See Note 3. Acquisitions, Divestitures and Merger.

(3) 2016 unproved property acquisition costs relate to the termination of the Marcellus Shale joint development. See Note 3. Acquisitions, Divestitures and Merger.

2015 proved and unproved property acquisitions include amounts allocated from the Rosetta Merger. See Note 3. Acquisitions, Divestitures and Merger.

2014 unproved property acquisition costs include $68 million and $160 million related to expanding our positions in the DJ Basin and Marcellus Shale, respectively, and $16 million for deepwater Gulf of Mexico lease blocks.

(4) 2016 exploration costs include drilling and completion of $1 million in the Marcellus Shale and $44 million in the deepwater Gulf of Mexico.

2015 exploration costs include drilling and completion of $4 million in the DJ Basin, $22 million in the deepwater Gulf of Mexico, $1 million in Equatorial Guinea and $4 million in Cyprus.

2014 exploration costs include drilling and completion of $14 million in the DJ Basin, $2 million in the Marcellus Shale, $117 million in the deepwater Gulf of Mexico, $16 million in Equatorial Guinea, $13 million in Israel and $4 million in Cyprus.

(5) Worldwide development costs include amounts spent to develop PUDs of approximately $656 million in 2016, $1.5 billion in 2015, and $2.0 billion in 2014.

US development costs include Noble Midstream Partners capital expenditures of approximately $50 million in 2016, gathering and processing assets acquired in the Rosetta Merger in 2015 and increases in asset retirement obligations of $18 million in 2016, $194 million in 2015, and $106 million in 2014.

Equatorial Guinea development costs include increases (decreases) in asset retirement obligations of $(10) million in 2015, and $34 million in 2014.

Israel development costs include increases in asset retirement obligations of $46 million in 2015, and $19 million in 2014.

Other International development costs include increases in asset retirement obligations of $2 million in 2015, and $71 million in 2014.

Capitalized Costs Relating to Oil and Gas Producing Activities (Unaudited) Aggregate capitalized costs relating to crude oil and natural gas producing activities are as follows:

	December 31,	
	2016	2015
(millions)		
Unproved Oil and Gas Properties [1]	$ 2,197	$ 2,151
Proved Oil and Gas Properties [2]	28,158	29,069
Total Oil and Gas Properties	30,355	31,220
Accumulated DD&A	(12,325)	(10,439)
Net Capitalized Costs	$ 18,030	$ 20,781
Company's Share of CONE Gathering Net Capitalized Costs	$ 440	$ 433

(1) 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 Permian Basin properties and $758 million related to the Marcellus Shale.

Unproved oil and gas property cost at December 31, 2015 include previous acquisition costs of $1.2 billion related to the Eagle Ford Shale and Permian Basin properties and $566 million related to the Marcellus Shale. See Note 3. Acquisitions, Divestitures and Merger.

(2) Proved oil and gas properties at December 31, 2016 include asset retirement costs of $897 million and exclude assets held for sale of $18 million.

Proved oil and gas properties at December 31, 2015 include asset retirement costs of $864 million and exclude assets held for sale of $67 million related to the Karish and Tanin natural gas discoveries offshore Israel.

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.

	United States	Israel [1]	Equatorial Guinea	Other Int'l [2]	Total
(millions)					
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 [6]	(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
December 31, 2014					
Future Cash Inflows [3]	$ 36,352	$ 15,110	$ 7,402	$ 11	$ 58,875
Future Production Costs [4]	(10,337)	(1,829)	(2,294)	(8)	(14,468)
Future Development Costs [5]	(7,272)	(724)	(186)	(100)	(8,282)
Future Income Tax Expense	(5,448)	(2,365)	(1,075)	—	(8,888)
Future Net Cash Flows	13,295	10,192	3,847	(97)	27,237
10% Annual Discount for Estimated Timing of Cash Flows	(6,040)	(6,240)	(995)	17	(13,258)
Standardized Measure of Discounted Future Net Cash Flows	$ 7,255	$ 3,952	$ 2,852	$ (80)	$ 13,979

(1) In accordance with the Israel Natural Gas Framework, we are required to reduce our ownership in the Tamar field to 25% by year-end 2021. During 2016, we reduced our ownership to 32.5% through a sale. Therefore, 2016 amounts reflect a 32.5% working interest, while 2015 and 2014 amounts reflect a 36% working interest. See Note 3. Acquisitions, Divestitures and Merger.

(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. For 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.

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	Other Int'l	Total
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
December 31, 2014					
Average Crude Oil and Condensate Price per Bbl	$ 86.88	$ 90.88	$ 97.88	$ 102.28	$ 89.27
Average Natural Gas Price per Mcf	3.99	6.14	0.27	—	4.49
Average NGL Price per Bbl	41.58	—	59.96	—	43.85

The discounted future net cash flows are computed using a 12-month average commodity price applied to our year-end quantities of proved reserves. 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 from the 12-month average price for 2016 would reduce the discounted future net cash flows before income taxes by approximately $910 million. We estimate that a 10% per Mcf reduction in the average price of natural gas from the 12-month average price for 2016 would reduce the discounted future net cash flows before income taxes by approximately $695 million.

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 $1.1 billion in 2017, $0.9 billion in 2018 and $800 million in 2019.

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.

Imbalance receivables and liabilities were as follows:

	Year Ended December 31,		
	2016	2015	2014
(millions)			
Imbalance Receivables [(1)]	$ —	$ 34	$ 34
Imbalance Liabilities [(1)]	—	34	33

(1) Imbalance receivables and liabilities for 2015 and 2014 related primarily to onshore US assets which were sold in 2016.

Imbalance receivables and liabilities have been excluded from the standardized measure of discounted future net cash flows for all years presented.

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,		
	2016	2015	2014
(millions)			
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Year	$ 6,628	$ 13,979	$ 14,090
Changes in Standardized Measure of Discounted Future Net Cash Flows			
Sales of Oil and Gas Produced, Net of Production Costs	(2,230)	(2,026)	(4,027)
Net Changes in Prices and Production Costs (1)	(593)	(12,603)	(1,090)
Extensions, Discoveries and Improved Recovery, Less Related Costs	463	442	1,457
Changes in Estimated Future Development Costs	(373)	1,135	(2,179)
Development Costs Incurred During the Period	1,090	2,639	4,042
Revisions of Previous Quantity Estimates	364	(1,051)	162
Purchases of Minerals in Place (2)	161	2,747	—
Sales of Minerals in Place	(951)	(46)	(268)
Accretion of Discount	919	1,789	1,919
Net Change in Income Taxes (3)	414	2,075	671
Change in Timing of Estimated Future Production and Other (4)	(206)	(2,452)	(798)
Aggregate Change in Standardized Measure of Discounted Future Net Cash Flows	$ (942)	$ (7,351)	$ (111)
Standardized Measure of Discounted Future Net Cash Flows, End of Year	$ 5,686	$ 6,628	$ 13,979

(1) The decrease in 2015 is driven primarily by lower 12-month average commodity prices.

(2) Purchase of minerals in 2015 relates to reserves acquired in the Rosetta Merger.

(3) The increase in 2015 reflects lower estimated future income tax expense primarily driven by lower 12-month average commodity prices. 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.

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)					
2016 [1] [3]					
Revenues	$ 724	$ 847	$ 910	$ 1,010	$ 3,491
Income (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)
Loss Per Share, Basic	(0.67)	(0.73)	(0.33)	(0.59)	(2.32)
Loss Per Share, Diluted	(0.67)	(0.73)	(0.33)	(0.59)	(2.32)
2015 [2] [3]					
Revenues	$ 767	$ 738	$ 819	$ 859	$ 3,183
Loss Before Income Taxes	(42)	(293)	(259)	(1,625)	(2,219)
Net Loss Attributable to Noble Energy	(22)	(109)	(283)	(2,027)	(2,441)
Loss Per Share, Basic	(0.06)	(0.28)	(0.67)	(4.73)	(6.07)
Loss Per Share, Diluted	(0.06)	(0.28)	(0.67)	(4.73)	(6.07)

(1) First quarter 2016 included the following:

- $44 million gain on commodity derivative instruments, including non-cash portion of loss on commodity derivative instruments of $134 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $80 million gain on extinguishment of debt.

Second quarter 2016 included the following:

- $151 million loss on commodity derivative instruments, including non-cash portion of loss on commodity derivative instruments of $295 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $25 million purchase price allocation adjustment related to Rosetta Merger (See Note 3. Merger, Acquisitions and Divestitures).

Third quarter 2016 included the following:

- $81 million undeveloped leasehold impairment expense (See Note 6. Capitalized Exploratory Well Costs and Undeveloped Leasehold Costs);
- $55 million gain on commodity derivative instruments, including non-cash portion of loss on commodity derivative instruments of $77 million (See Note 8. Derivative Instruments and Hedging Activities).

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);
- $87 million loss on commodity derivative instruments, including non-cash portion of loss on commodity derivative instruments of $201 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $92 million property impairment charges (See Note 5. Asset Impairments)

(2) First quarter 2015 included the following:

- $150 million gain on commodity derivative instruments, including non-cash portion of loss on commodity derivative instruments of $60 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $27 million property impairment charges (See Note 5. Asset Impairments).

Second quarter 2015 included the following:

- $87 million loss on commodity derivative instruments, including non-cash portion of loss on commodity derivative instruments of $274 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $15 million property impairment charges (See Note 5. Asset Impairments).

Third quarter 2015 included the following:

- $267 million gain on commodity derivative instruments, including non-cash portion of loss on commodity derivative instruments of $17 million (See Note 8. Derivative Instruments and Hedging Activities); and
- $71 million of other operating expenses associated with the Rosetta Merger.

Fourth quarter 2015 included the following:

- $171 million gain on commodity derivative instruments, including non-cash portion of loss on commodity derivative instruments of $157 million (See Note 8. Derivative Instruments and Hedging Activities);
- $779 million goodwill impairment charge (See Note 1. Summary of Significant Accounting Policies); and
- $490 million property impairment charges (See Note 5. Asset Impairments).

(3) The sum of the individual quarterly earnings (loss) may not agree with year-to-date earnings as each quarterly computation is based on the earnings 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, 2016. 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 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

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 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as a part of this report:

(3) Exhibits: The exhibits required to be filed by this Item 15 are set forth in the Index to Exhibits accompanying this report.

Item 16. Form 10-K Summary

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Executive Summary.

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 14, 2017	By: /s/ David L. Stover
	David L. Stover, Chairman of the Board, President and Chief Executive Officer
Date: February 14, 2017	By: /s/ Kenneth M. Fisher
	Kenneth M. Fisher, Executive Vice President, Chief Financial Officer
Date: February 14, 2017	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 14, 2017
/s/ Kenneth M. Fisher Kenneth M. Fisher	Executive Vice President, Chief Financial Officer (Principal Financial Officer)	February 14, 2017
/s/ Dustin A. Hatley Dustin A. Hatley	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 14, 2017
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 14, 2017
/s/ Michael A. Cawley Michael A. Cawley	Director	February 14, 2017
/s/ Edward F. Cox Edward F. Cox	Director	February 14, 2017
/s/ James E. Craddock James E. Craddock	Director	February 14, 2017
/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 14, 2017
/s/ Eric P. Grubman Eric P. Grubman	Director	February 14, 2017
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 14, 2017
/s/ Scott D. Urban Scott D. Urban	Director	February 14, 2017
/s/ William T. Van Kleef William T. Van Kleef	Director	February 14, 2017
/s/ Molly K. Williamson Molly K. Williamson	Director	February 14, 2017

INDEX TO EXHIBITS

Exhibit Number		Exhibit **
2.1	—	Agreement and Plan of Merger, dated as of January 13, 2017, by and among Noble Energy, Inc., Wild West Merger Sub Inc., NBL Permian LLC, and Clayton Williams Energy, Inc. (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Report: January 13, 2017) filed on January 17, 2017 and incorporated herein by reference).
2.2	—	Agreement and Plan of Merger, dated as of May 10, 2015, by and among Noble Energy, Inc., Bluebonnet Merger Sub Inc. and Rosetta Resources Inc. (filed as Exhibit 2.1 of the Registrant's Current Report on Form 8-K (Date of Report: May 10, 2015) filed on May 11, 2015 and incorporated herein by reference).
2.3	—	Exchange Agreement, executed October 29, 2016, by and between CNX Gas Company LLC and Noble Energy, Inc. (filed as Exhibit 2.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2016 and incorporated herein by reference).
3.1	—	Restated Certificate of Incorporation of Noble Energy Inc., (filed as Exhibit 3.3 to the Registrant's Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 and incorporated herein by reference).
3.2	—	By-Laws of Noble Energy, Inc. (as amended through July 27, 2016) (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Report: July 27, 2016) filed on July 29, 2016 and incorporated herein by reference).
3.3	—	Certificate of Elimination of the Series A Junior Participating Preferred Stock of Noble Energy, Inc. (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 and incorporated herein by reference).
3.4	—	Certificate of Elimination of the Series B Mandatorily Convertible Preferred Stock of Noble Energy, Inc. (filed as Exhibit 3.2 to the Registrant's Current Report on Form 8-K (Date of Report: July 26, 2016) filed on July 28, 2016 and incorporated herein by reference).
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 and incorporated herein by reference).
4.2	—	First Supplemental Indenture dated as of February 27, 2009, 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 8.25% Notes due 2019. (including the form of 2019 Notes) (filed as Exhibit 4.2 to the Registrant's Current Report on Form 8-K (Date of Report: February 24, 2009) filed February 27, 2009 and incorporated herein by reference).
4.3	—	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 and incorporated herein by reference).
4.4	—	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 and incorporated herein by reference).
4.5	—	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 and incorporated herein by reference).
4.6	—	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 and incorporated herein by reference).
4.7	—	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).

4.8	—	Indenture dated as of October 14, 1993 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 7¼% Notes Due 2023 (including the form of 2023 Notes) (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1993 and incorporated herein by reference).
4.9	—	Indenture dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to senior debt securities of Noble Energy, Inc. (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.1	—	First Indenture Supplement dated as of April 2, 1997, to Indenture dated as of April 1, 1997, between the Registrant and U.S. 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 as Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 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 U.S. 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 as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997 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 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 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 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 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 on 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 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 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 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 as Exhibit 10.18 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1995 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 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 10.1 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 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 on February 2, 2009 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 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 Event: February 1, 2005) filed February 7, 2005 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 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 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 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 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 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 herewith.
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, 2015 and incorporated herein by reference).
10.30*	—	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 and incorporated herein by reference).
10.31*	—	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 and incorporated herein by reference).

10.32*	—	Noble Energy, Inc. Change of Control Severance Plan for Executives (effective December 7, 2016) filed herewith.
10.33*	—	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 and incorporated herein by reference).
10.34*	—	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 and incorporated herein by reference).
10.35*	—	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 and incorporated herein by reference).
10.36*	—	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 and incorporated herein by reference).
10.37*	—	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 and incorporated herein by reference).
10.38*	—	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 and incorporated herein by reference).
10.39*	—	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 and incorporated herein by reference).
10.40	—	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 and incorporated herein by reference).
10.41	—	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 and incorporated herein by reference).
10.42*	—	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 and incorporated herein by reference).
10.43	—	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 on January 17, 2017 and incorporated herein by reference).
10.44	—	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 on January 17, 2017 and incorporated herein by reference).
10.45	—	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 on January 17, 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 U.S.C. 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 U.S.C. 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 U.S.C. 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 U.S.C. 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.

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
GSPA	Gas Sales Purchase Agreement
GHG	Greenhouse gas emissions
HH	Henry Hub index
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
NGL	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

Directors

David L. Stover •
Chairman, President and Chief Executive Officer, Noble Energy, Inc.

Jeffrey L. Berenson • •
Chairman and Chief Executive Officer, Berenson Holdings LLC

Michael A. Cawley • •
President and Manager, The Cawley Consulting Group, LLC

Edward F. Cox • • •
Chair, New York Republican State Committee

James E. Craddock • • •
Former Chief Executive Officer, Rosetta Resources Inc.

Thomas J. Edelman • • •
Managing Partner, White Deer Energy LP

Eric P. Grubman • •
Executive Vice President, National Football League

Kirby L. Hedrick • • •
Former Executive Vice President, Phillips Petroleum Company

Scott D. Urban • • •
Partner, Edgewater Energy LLC

William T. Van Kleef • •
Former Executive Vice President and Chief Operating Officer, Tesora Corporation

Molly K. Williamson • • •
Scholar with Middle East Institute

Committee Membership

- Audit Committee
- Compensation, Benefits and Stock Option Committee
- Corporate Governance and Nominating Committee
- Environment, Health and Safety Committee

Executive Officers

David L. Stover
Chairman, President and Chief Executive Officer, Noble Energy, Inc.

Kenneth M. Fisher
Executive Vice President and Chief Financial Officer

Susan M. Cunningham[1]
Executive Vice President, EHSR and New Frontiers

Gary W. Willingham
Executive Vice President, Operations

J. Keith Elliott
Senior Vice President, Eastern Mediterranean

Terry R. Gerhart
Senior Vice President, Global Operations Services

Arnold J. Johnson
Senior Vice President, General Counsel and Secretary

John T. Lewis
Senior Vice President, Corporate Development

Charles J. Rimer
Senior Vice President, U.S. Onshore

A. Lee Robison
Senior Vice President, Human Resources and Administration

Michael W. Putnam[2]
Vice President, Exploration

---

[1] *Retires March 24, 2017*
[2] *Retired January 3, 2017*

General Information

Annual Meeting
The Annual Meeting of Stockholders of Noble Energy, Inc. will be held on April 25, 2017, at 9:30 a.m. Central Time, at Four Seasons Hotel, 1300 Lamar Street, Houston, Texas 77010 All stockholders are cordially invited to attend.

Form 10-K
The company's Annual Report on Form 10-K for the year ended on December 31, 2016, as filed with the Securities and Exchange Commission (SEC), is included in this report. Additional copies are available without charge upon request by writing to: Investor Relations, Noble Energy, Inc., 1001 Noble Energy Way, Houston, Texas 77070; via the company's website: www.nblenergy.com; or via the SEC's website: www.sec.gov.

Noble Energy, Inc. Corporate Headquarters
1001 Noble Energy Way, Houston, Texas 77070
281.872.3100, www.nblenergy.com

Investor Relations
Brad Whitmarsh, Vice President, Investor Relations
281.872.3100, investor_relations@nblenergy.com

Communications and Media Relations
Ben Dillon, Vice President, Communications and Government Relations, 281.872.3100, media@nblenergy.com

Independent Public Accountants
KPMG LLP

Transfer Agent and Registrar
Wells Fargo Bank, N.A., Shareowner Services,
P.O. Box 64854, St. Paul, MN 55164-0854
800.468.9716, www.shareowneronline.com

Common Stock Listed
New York Stock Exhange, Symbol - NBL

Forward-Looking Statements and Other Matters
This 2016 Annual Report to Stockholders contains forward-looking statements based on expectations, estimates and projections as of the date of this report. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Disclosure Regarding Forward-Looking Statements" in Noble Energy's Form 10-K included in this report.

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The SEC permits the optional disclosure of probable and possible reserves; however, we have not disclosed our probable and possible reserves in our filings with the SEC. In this publication, we refer to certain non-engineer reserve quantities including gross resource, discovered gross resources and net unrisked resources, and the SEC guidelines strictly prohibit us from including them in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized. Investors are urged to consider closely the disclosures and risk factors in our Form 10-K included in this report.

MIX
Paper from responsible sources
FSC® C021351
www.fsc.org

noble energy

www.nblenergy.com