EP Energy Corp
Form 10-K
March 02, 2018
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K
(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to .
Commission File Number 001-36253

EP Energy Corporation
(Exact Name of Registrant as Specified in Its Charter)

Delaware	46-3472728
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
1001 Louisiana Street	
Houston, Texas	77002
(Address of Principal Executive Offices)	(Zip Code)

Telephone Number: (713) 997-1200
Internet Website: www.epenergy.com
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Class A Common Stock, par value $0.01 per share	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 o No x.
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 o No x.
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 x No o.
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o.
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. x

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

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

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

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

Aggregate market value of the Company’s common stock held by non-affiliates of the registrant as of June 30, 2017, was $146,818,078 based on the closing sale price on the New York Stock Exchange.

Indicate the number of shares outstanding of each of the registrant’s classes of common stock, as of the latest practicable date.

Class A Common Stock, par value $0.01 per share. Shares outstanding as of February 16, 2018: 251,349,018

Class B Common Stock, par value $0.01 per share. Shares outstanding as of February 16, 2018: 296,431

Documents Incorporated by Reference: Portions of the definitive proxy statement for the 2018 Annual Meeting of Stockholders of EP Energy Corporation, which will be held on May 16, 2018, are incorporated by reference into Part III of this Annual Report on Form 10-K.

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Below is a list of terms that are common to our industry and used throughout this document:

/d	=per day
Bbl	=barrel
Bcf	=billion cubic feet
Boe	=barrel of oil equivalent
Gal	=gallons
LLS	=light Louisiana sweet crude oil
MBoe	=thousand barrels of oil equivalent
MBbls	=thousand barrels
Mcf	=thousand cubic feet
MMBtu	=million British thermal units
MMBoe	=million barrels of oil equivalent
MMBbls	=million barrels
MMcf	=million cubic feet
MMGal	=million gallons
Mt. Belvieu	=Mont Belvieu natural gas liquids pricing index
NGLs	=natural gas liquids
NYMEX	=New York Mercantile Exchange
TBtu	=trillion British thermal units
WTI	=West Texas intermediate

When we refer to oil and natural gas in “equivalents,” we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. Equivalent volumes are computed with natural gas converted to barrels at a ratio of six Mcf to one Bbl. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to “us”, “we”, “our”, “ours”, “the Company”, or “EP Energy”, we are describing EP Energy Corporation and/or subsidiaries.

All references to “common stock” herein refer to Class A common stock.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that involve risks and uncertainties, many of which are beyond our control. These forward-looking statements are based on assumptions or beliefs that we believe to be reasonable; however, assumed facts almost always vary from the actual results and such variances can be material. Where we express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the stated expectation or belief will occur. The words “believe”, “expect”, “estimate”, “anticipate”, "plan", “intend”, "could" and “should” and similar expressions will generally ide forward-looking statements. All of our forward-looking statements are expressly qualified by these and the other cautionary statements in this Annual Report, including those set forth in Item 1A, "Risk Factors". Important factors that could cause our actual results to differ materially from the expectations reflected in our forward-looking statements include, among others:

- the volatility of and potential for sustained low oil, natural gas, and NGLs prices;
- the supply and demand for oil, natural gas and NGLs;
- changes in commodity prices and basis differentials for oil and natural gas;
- our ability to meet production volume targets;
- the uncertainty of estimating proved reserves and unproved resources;
- the future level of operating and capital costs;
- the availability and cost of financing to fund future exploration and production operations;
- the success of drilling programs with regard to proved undeveloped reserves and unproved resources;
- our ability to comply with the covenants in various financing documents;
- our ability to obtain necessary governmental approvals for proposed exploration and production projects and to successfully construct and operate such projects;
- actions by credit rating agencies;
- credit and performance risks of our lenders, trading counterparties, customers, vendors, suppliers and third party operators;
- general economic and weather conditions in geographic regions or markets we serve, or where operations are located, including the risk of a global recession and negative impact on demand for oil and/or natural gas;
- the uncertainties associated with governmental regulation, including any potential changes in federal and state tax laws and regulations;
- competition; and
- the other factors described under Item 1A, “Risk Factors,” on pages 15 through 35 of this Annual Report on Form 10-K, and any updates to those factors set forth in our subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

In light of these risks, uncertainties and assumptions, the events anticipated by these forward-looking statements may not occur, and, if any of such events do occur, we may not have anticipated the timing of their occurrence or the extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of these forward-looking statements. These forward-looking statements speak only as of the date made, and we undertake no obligation, other than as required by applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

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PART I

ITEM 1. BUSINESS

Overview

EP Energy Corporation (EP Energy), a Delaware corporation formed in 2013, is an independent exploration and production company engaged in the acquisition and development of unconventional onshore oil and natural gas properties in the United States. Our strategy is to invest in opportunities that provide the highest return across our asset base, continually seek out operating and capital efficiencies, effectively manage costs, and identify accretive acquisition opportunities and divestitures, all with the objective of enhancing our portfolio, growing asset value, improving cash flow, increasing financial flexibility and providing an attractive return to our shareholders.

We operate through a diverse base of producing assets and are focused on the development of our drilling inventory located in three areas: the Permian basin in West Texas, the Eagle Ford Shale in South Texas, and the Altamont Field in the Uinta basin in Northeastern Utah. As of December 31, 2017, we had proved reserves of 392.1 MMBoe (52% oil and 72% liquids) and for the year ended December 31, 2017, we had average net daily production of 82,257 Boe/d (56% oil and 74% liquids).

Each of our areas is characterized by a long-lived reserve base and high drilling success rates. We have established significant contiguous leasehold positions in each area, representing approximately 455,000 net (608,000 gross) acres in total.

We evaluate opportunities in our portfolio that are aligned with our strategy and our core competencies and that are in areas that we believe can provide an attractive return on our invested dollars and offer a competitive advantage. In addition to opportunities in our current portfolio, strategic acquisitions of leasehold acreage or acquisitions of producing assets can allow us to leverage existing expertise in our operating areas, balance our exposure to regions, basins and commodities, help us achieve or enhance risk-adjusted returns competitive with those available in our existing programs and increase our reserves. We also continuously evaluate our asset portfolio and will sell oil and natural gas properties if they no longer meet our long-term objectives.

The following table provides a summary of oil, natural gas and NGLs reserves as of December 31, 2017 and production data for the year ended December 31, 2017 for each of our areas of operation.

	Estimated Proved Reserves[1]						
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Liquids (%)	Proved Developed (%)[2]	Average Net Daily Production (MBoe/d)
Eagle Ford Shale	86.1	32.1	182.0	148.5	80 %	56 %	35.7
Permian	55.2	47.4	313.6	154.9	66 %	49 %	28.7
Altamont	62.6	—	156.7	88.7	71 %	66 %	17.9
Total	203.9	79.5	652.3	392.1	72 %	56 %	82.3

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $51.34 per Bbl (WTI) and $2.98 per MMBtu (Henry Hub).

(2) Includes 13 MMBoe of proved developed non-producing reserves representing 3% of total net proved reserves at December 31, 2017.

Approximately 205 MMBoe, or 52%, of our total proved reserves are proved developed producing assets, which generated average production of 82.3 MBoe/d in 2017 from approximately 1,608 wells. As of December 31, 2017, we had approximately 204 MMBbls of proved oil reserves, 80 MMBbls of proved NGLs reserves and 652 Bcf of proved natural gas reserves, representing 52%, 20% and 28%, respectively, of our total proved reserves. For the year ended December 31, 2017, 74% of our production was related to oil and NGLs versus 70% in 2016.

As of December 31, 2017, we operated 92% of our producing wells. This control provides us with flexibility around the amount and timing of capital spending and has allowed us to improve our capital and operating efficiencies. We also employ a function-based organizational structure to accelerate knowledge sharing, innovation, evaluation and target efficiencies across our drilling, completion and operating activities across our operating areas. In 2017, we completed 149 wells with a success rate of 100%, adding approximately 24 MMBoe of proved reserves (70% of which were liquids). As of December 31, 2017, we also had a total of 47 wells drilled, but not completed across our programs.

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Our Properties

Eagle Ford Shale. The Eagle Ford Shale, located in South Texas, is one of the premier unconventional oil plays in the United States. We were an early entrant into this play in late 2008, and since that time have acquired a leasehold position in the core of the oil window, primarily in La Salle County. The Eagle Ford formation in La Salle County has up to 125 feet of net thickness (165 feet gross). Due to its high carbonate content, the formation is also very brittle, and exhibits high productivity when fractured. As of December 31, 2017, we had 92,997 net (104,108 gross) acres in the Eagle Ford.

During 2017, we invested $227 million in capital in our Eagle Ford Shale and operated an average of approximately one drilling rig. As of December 31, 2017, we had 635 net producing wells (628 net operated wells) and are currently running two rigs in this program. For the year ended December 31, 2017, our average net daily production was 35,667 Boe/d, representing a decrease of 18% over the same period in 2016 due to natural declines and the slower pace of development from reduced capital spending since 2016.

In December 2017, we entered into an agreement to acquire certain producing properties and undeveloped acreage primarily in La Salle County. This acquisition represents a 26 percent expansion of our current Eagle Ford acreage position or approximately 24,500 net acres for approximately $245 million subject to customary closing adjustments. We closed the acquisition on January 31, 2018.

Permian. The Permian basin is characterized by numerous, stacked oil reservoirs that provide excellent targets for horizontal drilling. In 2009 and 2010, we leased 138,130 net (138,469 gross) acres on the University of Texas Land System in the Permian basin, located primarily in Reagan, Crockett, Upton and Irion counties.

Our large, contiguous acreage positions are characterized by stacked pay zones, including the Wolfcamp A, B, and C zones, which combine for over 750 feet of net (approximately 1,000 feet of gross) thickness. The Permian has high organic content and is composed of interbedded shale, silt, and fine-grained carbonate that respond favorably to fracture stimulation. As of December 31, 2017, we had 182,102 net (184,826 gross) acres in the Permian.

The acreage is also prospective for the Cline Shale, which has approximately 100 feet of net (approximately 200 feet of gross) thickness, and potential vertical drilling locations in the Spraberry and other stacked formations.

During 2017, we invested $267 million in capital (including approximately $29 million in acquisition capital) in the Permian and operated an average of approximately two drilling rigs. As of December 31, 2017, we had 335 net producing wells (332 net operated wells). We are currently running one rig in this program. For the year ended December 31, 2017, our average net daily production was 28,711 Boe/d, representing an increase of 34% over 2016 reflecting incremental capital allocated to this program in 2016 and 2017.

In January 2017, we entered into a drilling joint venture to accelerate and fund future oil and natural gas development in the Permian basin. Under the joint venture, our partner may participate in the development of up to 150 wells in two separate 75 well tranches primarily in Reagan and Crockett counties. We retain operational control of the joint venture assets. The first wells under the joint venture began producing in January 2017 and as of December 31, 2017, we have drilled and completed 58 wells. For a further discussion of this joint venture, see Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Our Business” and Item 8, “Financial Statements and Supplementary Data”, Note 11.

In 2016, we amended our Consolidated Drilling and Development Unit Agreement with the University of Texas Land System in the Permian basin to provide flexibility to extend the time frame to hold our acreage by nearly four years to the end of 2021, with an increase in annual well completion requirements from six wells per year to 34, 55 and 55 wells per year in 2016, 2017 and 2018, respectively. We fulfilled this requirement in 2016 and 2017. The amendment has a variable royalty that improves well returns in a lower price environment. The rates associated with the variable royalty are determined using a rolling average six month price with royalty rates of 12.5% at an average price of $50 per Bbl (WTI) and below, 18.75% at an average price of $50.01 to $60 per Bbl (WTI), 25% at an average price of $60.01 to $80 per Bbl (WTI) and 28% above $80 per Bbl (WTI).

Altamont. The Altamont Field is located in the Uinta basin in northeastern Utah. The Uinta basin is characterized by naturally fractured, tight-oil sands and carbonates with multiple pay zones. Our operations are primarily focused on developing the Altamont Field Complex (comprised of the Altamont, Bluebell and Cedar Rim fields), which is the largest field in the basin. We own 179,978 net (318,877 gross) acres in Duchesne and Uinta Counties. The Altamont Field Complex has a gross pay interval thickness of over 4,300 feet and we believe the Wasatch and Green River formations are ideal targets for low-risk, infill, vertical drilling and modern fracture stimulation techniques. Our commingled production is from over 1,500 feet of net stimulated rock. Our current activity is mainly focused on the development of our vertical inventory on 80-acre and 160-acre

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spacing and we continue to evaluate horizontal opportunities. Industry activity has focused on horizontal drilling in the Wasatch and Green River formations testing tight carbonate and sand intervals and has also piloted 80-acre vertical downspacing in these formations. Due to the largely held-by-production nature of our acreage position, if horizontal drilling is successful, it will result in additional opportunities that could be added to our inventory of drilling locations.

During 2017, we invested $93 million in capital in Altamont and operated an average of approximately two drilling rigs. As of December 31, 2017, we had 385 net producing wells (377 net operated wells) and are currently running two rigs in this program. For the year ended December 31, 2017, our average net daily production was 17,795 Boe/d, representing an increase of 8% over 2016.

In May 2017, we entered into a drilling joint venture to accelerate and fund future oil and natural gas development in Altamont. Under the joint venture, our partner is participating in the development of 60 wells and will provide a capital carry in exchange for a 50 percent working interest in the joint venture wells. The first wells under the joint venture began producing in July 2017 and as of December 31, 2017, we have drilled and completed 16 wells.

In December 2017, we entered into an agreement to sell acreage in the Altamont area for approximately $180 million of cash proceeds subject to customary closing adjustments. This divestiture includes 4.5 MMBoe of proved developed reserves and approximately 13 percent of our current Altamont acreage position or approximately 23,330 net acres. We closed this transaction in February 2018.

The following table provides a summary of acreage and gross operated wells completed in our areas as of December 31, 2017:

	Acres		Gross Operated Wells Completed (#)
	Gross	Net	
Eagle Ford Shale	104,108	92,997	53
Permian	184,826	182,102	71
Altamont	318,877	179,978	25
Total	607,811	455,077	149

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Oil and Natural Gas Properties

Oil, Natural Gas and NGLs Reserves and Production

Proved Reserves

The table below presents information about our estimated proved reserves as of December 31, 2017, based on our internal reserve report. The reserve data represents only estimates which are often different from the quantities of oil and natural gas that are ultimately recovered. The risks and uncertainties associated with estimating proved oil and natural gas reserves are discussed further in Item 1A, “Risk Factors”. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at December 31, 2017.

	Net Proved Reserves[(1)]				
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Percent (%)
Reserves by Classification					
Proved Developed					
Eagle Ford Shale	49.2	17.6	100.3	83.5	21 %
Permian	25.3	24.4	160.0	76.4	20 %
Altamont	39.8	—	111.8	58.4	15 %
Total Proved Developed[(2)]	114.3	42.0	372.1	218.3	56 %
Proved Undeveloped					
Eagle Ford Shale	36.9	14.5	81.7	65.0	16 %
Permian	29.9	23.0	153.6	78.5	20 %
Altamont	22.8	—	44.9	30.3	8 %
Total Proved Undeveloped	89.6	37.5	280.2	173.8	44 %
Total Proved Reserves	203.9	79.5	652.3	392.1	100 %

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $51.34 per Bbl (WTI) and $2.98 per MMBtu (Henry Hub). For a further discussion of our proved reserves and changes therein see Part II, Item 8, "Financial Statements and Supplementary Data", under the heading Supplemental Oil and Natural Gas Operations.

(2) Includes 205 MMBoe of proved developed producing reserves representing 52% of total net proved reserves and 13 MMBoe of proved developed non-producing reserves representing 3% of total net proved reserves at December 31, 2017.

Our reserves in the table above are consistent with estimates of reserves filed with other federal agencies except for differences of less than 5% resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. Our estimated net proved reserves were prepared by our internal reserve engineers and audited by Ryder Scott Company, L.P. (Ryder Scott), our independent petroleum engineering consultants.

The table below presents net proved reserves as reported and sensitivities related to our estimated proved reserves based on differing price scenarios as of December 31, 2017.

	Net Proved Reserves (MMBoe)
As Reported	392.1
10 percent increase in commodity prices	393.9
10 percent decrease in commodity prices	389.5

The sensitivities in the table above were based on the average first day of the month spot price for the preceding 12-month period of $51.34 per barrel of oil (WTI) and $2.98 per MMBtu of natural gas (Henry Hub) used to determine net proved reserves at December 31, 2017.

We employ a technical staff of engineers and geoscientists that perform technical analysis of each undeveloped location. The staff uses industry accepted practices to estimate, with reasonable certainty, the economically producible oil and natural gas. The practices for estimating hydrocarbons in place include, but are not limited to, mapping, seismic interpretation of two-dimensional and/or three-dimensional data, core analysis, mechanical properties of formations, thermal maturity, well logs of existing penetrations, correlation of known penetrations, decline curve analysis of producing locations with significant production history, well testing, static bottom hole testing, flowing bottom hole pressure analysis and pressure and rate transient analysis.

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Our primary internal technical person in charge of overseeing our reserves estimates has a B.S. degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers. He is the director of the reservoir engineering evaluations and strategic planning groups of the company. In this capacity, he oversees the reserve reporting and technical support groups. He has more than 24 years of industry experience in various domestic and international engineering and management roles. For a discussion of the internal controls over our proved reserves estimation process, see Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Estimates".

Ryder Scott conducted an audit of the estimates of net proved reserves that we prepared as of December 31, 2017. In connection with its audit, Ryder Scott reviewed 100% (by volume) of our total net proved reserves on a barrel of oil equivalent basis, representing 99% of the total discounted future net cash flows of these net proved reserves. Ryder Scott did not audit our non-operated properties, which are less than 1% of our net proved reserves by volume. For the audited properties, 100% of our total net proved undeveloped (PUD) reserves were evaluated. Ryder Scott concluded that the overall procedures and methodologies that we utilized in preparing our estimates of net proved reserves as of December 31, 2017 complied with current SEC regulations and the overall net proved reserves for the reviewed properties as estimated by us are, in aggregate, reasonable within the established audit tolerance guidelines of 10% as set forth in the Society of Petroleum Engineers auditing standards. Ryder Scott's report is included as an exhibit to this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the reserves audit by Ryder Scott has a B.S. degree in chemical engineering. He is a Licensed Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers and has more than 14 years of experience in petroleum reserves evaluation.

In general, the volume of production from oil and natural gas properties declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties with proved reserves, or both, our proved reserves will decline as they are produced. Recovery of PUD reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of PUD reserves and proved non-producing reserves are inherently subject to greater uncertainties than estimates of proved producing reserves. For further discussion of our reserves, see Part II, Item 8, "Financial Statements and Supplementary Data", under the heading Supplemental Oil and Natural Gas Operations.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2017, we have 174 MMBoe of PUD reserves in our areas, all of which are scheduled to be developed within five years of their initial recording. Estimated capital expenditures to develop our PUD reserves (convert PUD reserves to proved developed reserves) are based upon a long-range plan approved by the Board of Directors. All PUD locations are surrounded by producing properties, and a majority of our PUDs directly offset a producing property. Where we have recorded PUDs beyond one location away from a producing property, reasonable certainty of economic producibility has been established by reliable technology in our areas, including field tests that demonstrate consistent and repeatable results within the formation being evaluated.

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We assess our PUD reserves on a quarterly basis. The following table summarizes our changes in PUDs for the years ended December 31, 2016 and December 31, 2017, respectively (in MMBoe):

Balance, December 31, 2015	289.4
Extensions and discoveries	54.9
Revisions due to prices	(4.4)
Revisions other than prices	(87.4)
Transfers to proved developed	(24.7)
Balance, December 31, 2016	227.8
Extensions and discoveries	15.1
Revisions due to prices	1.4
Revisions other than prices	(23.4)
Transfers to proved developed	(30.7)
Divestitures	(16.4)
Balance, December 31, 2017	173.8

Extensions and discoveries in 2016 and 2017 are primarily related to drilling activities in the Eagle Ford, Permian and Altamont areas. Revisions due to prices represent PUD revisions due to increases or decreases in commodity prices (using SEC 12-month average pricing). For the year ended December 31, 2017, revisions other than prices include, among other items, negative revisions of 23 MMBoe due to a reallocation of capital in our development areas; a negative PUD ownership reversion of 10 MMBoe as a result of our variable royalty agreement in the Permian; and a positive revision of 10 MMBoe from improved operating expenses and planned development of longer lateral PUDs. The year ended December 31, 2017 includes 63 MMBoe of our PUDs that have a positive undiscounted value, but a negative value when discounted at 10 percent. The majority of these PUDs become negative at a 10 percent discount rate due to an ownership reversion associated with a long-term drilling commitment. The divestiture of 16 MMBoe is related to drilling joint ventures we entered into during 2017. For the year ended December 31, 2016, revisions other than prices include, among other items, negative revisions of 98 MMBoe due to reductions in our estimated capital in our five year development plan, partially offset by positive PUD revisions of 17 MMBoe due to ownership revisions.

During 2017, 2016 and 2015, we spent approximately $377 million, $281 million and $835 million, respectively, to convert approximately 13% or 31 MMBoe, 9% or 25 MMBoe and 14% or 55 MMBoe, respectively, of our prior year-end PUD reserves to proved developed reserves. The lower conversion rates in 2016 and 2015 are a result of reductions in actual capital spending compared to what was planned in response to the downturn in prices that occurred and has continued since the fourth quarter of 2014. In 2018, 2019 and 2020 we estimate we will spend approximately $429 million, $455 million and $554 million to develop our PUD reserves, respectively, based on our December 31, 2017 internal reserve report. At this level of spending from 2018 through 2020, we will develop approximately 64% of our existing PUD reserves with the remaining balance of PUDs to be developed in the succeeding two years. We believe we have the ability, and we have the intent to develop our PUDs over five years based on our strategic plan. The actual amount and timing of our forecasted expenditures will depend on a number of factors, including actual drilling results, service costs and future commodity prices which in the future could be lower than those in our projected long-range plan.

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Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2017, (ii) our interest in oil and natural gas wells at December 31, 2017 and (iii) our development wells completed during the years 2015 through 2017. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

Acreage

	Developed		Undeveloped		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Eagle Ford Shale	45,633	41,309	58,475	51,688	104,108	92,997
Permian	24,014	21,403	160,812	160,699	184,826	182,102
Altamont	87,140	64,838	231,737	115,140	318,877	179,978
Other	95,621	6,384	231,571	111,069	327,192	117,453
Total Acreage	252,408	133,934	682,595	438,596	935,003	572,530

(1) Gross interest reflects the total acreage we participate in regardless of our ownership interest in the acreage.
(2) Net interest is the aggregate of the fractional working interests that we have in the gross acreage.

Our net developed acreage is concentrated in Texas (50%) and Utah (48%). Our net undeveloped acreage is concentrated in Texas (50%), Utah (27%), Wyoming (11%) and West Virginia (10%). Approximately 6%, 3% and 2% of our net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2018, 2019 and 2020, respectively. We employ various techniques to manage the expiration of leases, including drilling the acreage ourselves prior to lease expiration, entering into farm-out or joint development agreements with other operators or extending lease terms.

Productive Wells

	Oil		Natural Gas		Total		Wells In Progress at December 31, 2017(1)	
	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)(4)	Gross(2)	Net(3)
Eagle Ford Shale	731	635	—	—	731	635	31	28
Permian	367	335	—	—	367	335	21	19
Altamont	507	384	3	1	510	385	6	4
Total Productive Wells	1,605	1,354	3	1	1,608	1,355	58	51

(1) Comprised of wells that were spud as of December 31, 2017 and have not been completed.
(2) Gross interest reflects the total wells we participated in, regardless of our ownership interest.
(3) Net interest is the aggregate of the fractional working interests that we have in the gross wells or gross wells drilled.
(4) At December 31, 2017, we operated 1,337 of the 1,355 net productive wells.

Wells Completed(1)

	Net Development(2)		
	2017	2016	2015(3)
Total Productive Wells Completed	106	94	180

(1) No dry wells or exploratory wells were drilled or completed during the years 2015 through 2017.
(2) Net development is the aggregate of the fractional working interests that we have in the gross wells completed.
(3) December 31, 2015 includes four net wells in our Haynesville Shale, which was sold in May 2016.

The performance above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells completed and the amount of oil and natural gas that may ultimately be recovered.

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Net Production, Sales Prices, Transportation and Production Costs

The following table details our net production volumes, and prices and costs per unit for each of the three years ended December 31:

	2017	2016	2015
Volumes:			
Total Net Production Volumes			
Oil (MBbls)	16,833	17,061	22,078
Natural Gas (MMcf)(1)	46,356	57,799	75,533
NGLs (MBbls)	5,465	5,383	5,366
Total Equivalent Volumes (MBoe)	30,024	32,077	40,033
MBoe/d(2)	82.3	87.6	109.7
Net Production Volumes by Area			
Eagle Ford Shale			
Oil (MBbls)	8,168	9,679	14,220
Natural Gas (MMcf)	14,114	18,442	21,212
NGLs (MBbls)	2,498	3,164	3,483
Total Eagle Ford Shale (MBoe)	13,018	15,916	21,238
Permian			
Oil (MBbls)	4,168	3,155	3,322
Natural Gas (MMcf)	20,117	14,823	12,396
NGLs (MBbls)	2,959	2,210	1,872
Total Permian (MBoe)	10,480	7,836	7,260
Altamont			
Oil (MBbls)	4,493	4,224	4,532
Natural Gas (MMcf)	11,992	10,851	10,299
NGLs (MBbls)	4	6	9
Total Altamont (MBoe)	6,495	6,039	6,257
Other			
Oil (MBbls)	4	3	4
Natural Gas (MMcf)(1)	133	13,684	31,626
NGLs (MBbls)	5	2	3
Total Other (MBoe)	31	2,286	5,278
Prices and Costs per Unit:(3)			
Oil Average Realized Sales Price ($/Bbl)			
Physical Sales	$48.23	$38.24	$44.28
Including Financial Derivatives(4)	$53.50	$74.88	$82.18
Natural Gas Average Realized Sales Price ($/Mcf)			
Physical Sales	$2.32	$1.95	$2.27
Including Financial Derivatives(4)	$2.47	$2.19	$3.59
NGLs Average Realized Sales Price ($/Bbl)			
Physical Sales	$18.87	$12.02	$11.22
Including Financial Derivatives(4)	$18.46	$12.19	$12.36
Average Transportation Costs			
Oil ($/Bbl)	$1.86	$1.88	$1.55
Natural Gas ($/Mcf)	$1.79	$1.32	$0.91
NGLs ($/Bbl)	$0.15	$0.22	$2.31
Average Lease Operating Expenses ($/Boe)	$5.42	$4.97	$4.64

Average Production Taxes ($/Boe)	$2.02	$1.37	$1.83

(1) Natural gas volumes in 2016 and 2015 include 13,556 MMcf and 31,521 MMcf, respectively, from the Haynesville Shale which was sold in May 2016.

(2) The years ended December 31, 2016 and 2015 include 6.2 MBoe/d and 14.4 MBoe/d, respectively, from the Haynesville Shale.

(3) For the year ended December 31, 2017, there were no oil purchases associated with managing our physical oil sales. Oil prices for the years ended December 31, 2016 and 2015 reflect operating revenues for oil reduced by $1 million and $3 million, respectively, for oil purchases associated with managing our physical oil sales. Natural gas prices for the years ended December 31, 2017, 2016 and 2015 reflect operating revenues for natural gas reduced by $2 million, $9 million and $28 million, respectively, for natural gas purchases associated with managing our physical sales.

(4) Includes actual cash settlements related to financial derivatives.

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Acquisition, Development and Exploration Expenditures

See Part II, Item 8, "Financial Statements and Supplementary Data" under the heading Supplemental Oil and Natural Gas Operations in the Total Costs Incurred table for details on our acquisition, development and exploration expenditures.

Transportation, Markets and Customers

Our marketing strategy seeks to ensure maximum deliverability of our physical production at the maximum realized prices. We leverage knowledge of markets and transportation infrastructure to enter into beneficial downstream processing, treating and marketing contracts. We primarily sell our domestic oil and natural gas production to third parties at spot market prices, while we sell our NGLs at market prices under monthly or long-term contracts. We typically sell our oil production to a relatively small number of creditworthy counterparties, as is customary in the industry. For the year ended December 31, 2017, eleven purchasers accounted for approximately 89% of our oil revenues. The top two purchasers are: Flint Hills Resources, LP (an affiliate of Koch Industries) and Shell Trading U.S. Co. (an affiliate of Shell Oil Company), which together accounted for approximately 39% of our oil revenues. Across all of our areas, we maintain adequate gathering, treating, processing and transportation capacity, as well as downstream sales arrangements, to accommodate our production volumes.

In our Eagle Ford Shale area, we are connected to the Camino Real oil gathering system and to the NuStar Energy system. The vast majority of our oil production flows on Camino Real, a 68-mile long pipeline with over 110,000 Bbls/d of capacity and a gravity bank that allows for oil blending to maintain attractive API levels. We have 80,000 Bbls/d of firm capacity on this oil system, of which we utilized an average of 32% during December 2017 and 33% on average for the year. The system delivers oil to the Storey Oil Terminal east of Cotulla, Texas, southeast of Gardendale, Texas. From the Storey Oil Terminal, oil can be pumped into Harvest’s Arrowhead #1 and/or #2 pipelines, as well as the Plains All American Pipeline connection to the Gardendale Hub. Oil can also be loaded into trucks out of the Storey Oil Terminal or out of the numerous central tank batteries throughout our field, providing additional deliverability, reliability and flexibility. We currently market our oil either at the Storey Oil Terminal, Gardendale or at our central tank batteries under a combination of short and long-term contracts, ranging from monthly deals to multi-year term sales. With adequate takeaway capacity in the region and close proximity to the Gulf Coast refining complex, we believe we have sufficient capacity on our contracts and do not anticipate any issues with marketing and delivering volumes from the Eagle Ford Shale.

Our Eagle Ford natural gas production flows on either the Camino Real gas gathering system or the Frio LaSalle Pipeline system with the majority flowing on the Camino Real gas gathering system. The Camino Real gas gathering system receives high-pressure, unprocessed wellhead gas into an 83-mile pipeline with capacity up to 150 MMcf/d. The gas is then redelivered into interconnects with ETC Texas Pipeline LTD, Enterprise Hydrocarbons LP, Regency Energy Partners LP and Eagle Ford Gathering LLC. We currently have 125 MMcf/d of firm transportation capacity on Camino Real, of which we used an average of 42% during December 2017, and we have additional capacity available as needed. We have firm gas gathering, processing and transportation agreements on three of the interconnected gas pipelines downstream of the Camino Real system, with a minimum capacity of approximately 100 MMBtu/d and rights to increase firm capacity as necessary. In addition, gas produced from our northwest acreage position within the Eagle Ford area is connected to the Frio LaSalle Pipeline system, which provides access to firm H2S treating and processing. Frio LaSalle can either return gas to the Camino Real system or, after processing, deliver to various Texas intrastate pipelines and a mix of interstates, such as Texas Eastern Transmission, Tennessee Gas Pipeline, and Transco. We market our physical gas to various purchasers at spot market prices.

In the Permian basin, we continue to leverage significant legacy gathering, processing and transportation infrastructure. For natural gas, we are connected to the West Texas Gas (WTG), DCP Midstream LP, Targa Pipeline Mid-Continent WestTex LLC and Lucid Energy WesTex LLC gathering systems, and we process a majority of our gas at the WTG Benedum & Sonora gas plants. We receive Waha pricing for our natural gas and Mt. Belvieu pricing for our NGLs. “Waha pricing” refers to the published index price for spot and monthly physical natural gas purchases and sales made into interstate and intrastate pipelines at the outlet of the Waha header system and in the Waha vicinity in the Permian basin in West Texas. “Mt. Belvieu pricing” refers to the spot market price for NGLs delivered into the Mt. Belvieu NGL processing and storage hub in Mt. Belvieu, Texas. Our crude oil production facilities are connected to a third party oil gathering system that delivers to a Plains All American Pipeline at Owens Station in Reagan County, Texas, the Centurion Cline Shale Pipeline at Barnhart in Irion County, Texas and to the Magellan Longhorn pipeline in Crockett County, Texas. We sell our pipeline delivered crude to multiple purchasers under both short and long-term contracts at WTI-based pricing. We also maintain the capability to truck crude oil to those same purchasers under similarly-priced contracts to provide additional flow assurance. Given current Permian basin takeaway capacity, we anticipate no limitations moving physical crude oil to market and expect regional pricing to remain correlated with NYMEX/WTI.

In our Altamont area, the wax crude we produce is sold at the wellhead to multiple purchasers who transport the oil via truck to downstream refineries. We sell most of the oil we produce in the basin to Salt Lake City refineries under long-term

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sales agreements that accommodate our production forecasts. Our produced natural gas is gathered and processed at the Altamont plant, a third-party-owned processing facility, under a long-term sales agreement that provides for residue gas return for operational use.

While most of our physical production is priced off spot market indices, we actively manage the volatility of spot market pricing through our risk management program. We enter into financial derivatives contracts on our oil, natural gas and a portion of our NGLs production to stabilize our cash flows, reduce the risk of downward commodity price movements and protect the economic assumptions associated with our capital investment program. We employ a disciplined risk management program that utilizes risk control processes. For a further discussion of these risk management activities and derivative contracts, see Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Competitors

The exploration and production business is highly competitive in the search for and acquisition of additional oil and natural gas reserves and in the sale of oil, natural gas and NGLs. Our competitors include major and intermediate sized oil and natural gas companies, independent oil and natural gas operators and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include financial resources, price and contract terms, our ability to access drilling, completion and other equipment and our ability to hire and retain skilled personnel on a timely and cost effective basis. Ultimately, our future success in this business will be dependent on our ability to find and/or fund the acquisition and development of additional reserves at costs that yield acceptable returns on the capital invested.

Use of 3-D Seismic Data

Within our areas we have an inventory of approximately 1,463 square miles of 3-D seismic data providing approximately 49% coverage of our leased acreage in those areas. We use our 3-D seismic data to improve our geologic models for each area. In the Eagle Ford and the Permian, detailed maps of structural features (e.g., natural fractures, faulting and stratigraphic discontinuities) are used to position well bore laterals to optimally exploit oil bearing zones and navigate drilling hazards. In Altamont, data analytics are run using 3-D seismic attributes to identify ideal locations in the reservoir and estimate resource distribution. Seismic data sets are continually updated to keep pace with technological advancements in seismic processing.

Regulatory Environment

Our oil and natural gas exploration and production activities are regulated at the federal, state and local levels in the United States. These regulations include, but are not limited to, those governing the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. We are also subject to various governmental safety and environmental regulations in the jurisdictions in which we operate.

Our operations under federal oil and natural gas leases are regulated by the statutes and regulations of the Department of the Interior (DOI) that currently impose liability upon lessees for the cost of environmental impacts resulting from their operations. Royalty obligations on all federal leases are regulated by the Office of Natural Resources Revenue within the DOI, which has promulgated valuation guidelines for the payment of royalties by producers. These laws and regulations affect the construction and operation of facilities, water disposal rights and drilling operations, among other items. In addition, we maintain insurance to limit exposure to sudden and accidental pollution liability exposures.

Hydraulic Fracturing. Hydraulic fracturing is a process of pumping fluid and proppant (usually sand) under high pressure into deep underground geologic formations that contain recoverable hydrocarbons. These hydrocarbon formations are typically thousands of feet below the surface. The hydraulic fracturing process creates small fractures in the hydrocarbon formation. These fractures allow natural gas and oil to move more freely through the formation to the well and finally to the surface production facilities. We use hydraulic fracturing to maximize productivity of our oil and natural gas wells in our areas, and our proved undeveloped oil and natural gas reserves will be developed using hydraulic fracturing. For the year ended December 31, 2017, we incurred costs of approximately $222 million associated with hydraulic fracturing.

Hydraulic fracturing fluid is typically composed of over 99% water and proppant, which is usually sand. The other 1% or less of the fluid is composed of additives that may contain acid, friction reducer, surfactant, gelling agent and scale inhibitor. We retain service companies to conduct such operations and we have worked with several service companies to evaluate, test and, where appropriate, modify our fluid design to reduce the use of chemicals in our fracturing fluid. We have worked closely with our service companies to provide voluntary and regulatory disclosure of our hydraulic fracturing fluids.

In order to protect surface and groundwater quality during the drilling and completion phases of our operations, we follow applicable industry practices and legal requirements of the applicable state oil and natural gas commissions with regard

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to well design, including requirements associated with casing steel strength, cement strength and slurry design. Our activities in the field are monitored by state and federal regulators. Key aspects of our field protection measures include: (i) pressure testing well construction and integrity, (ii) casing and cementing practices to ensure pressure management and separation of hydrocarbons from groundwater, and (iii) public disclosure of the contents of hydraulic fracturing fluids.

In addition to these measures, our drilling, casing and cementing procedures are designed to prevent fluid migration and typically include some or all of the following:

- Our drilling process executes several repeated cycles conducted in sequence—drill, set casing, cement casing and then test casing and cement for integrity before proceeding to the next drilling interval.
- Conductor casing is drilled and cemented or driven in place. This string serves as the structural foundation for the well. Conductor casing is not necessary or required for all wells.
- Surface casing is set and is cemented in place. Surface casing is set on all wells. The purpose of the surface casing is to isolate and protect Underground Sources of Drinking Water (USDW) as identified by federal and state regulatory bodies. The surface casing and cement isolates wellbore materials from any potential contact with USDWs.
- Intermediate casing is set through the surface casing to a depth necessary to isolate abnormally pressured subsurface formations from normally pressured formations. Intermediate casing is not necessary or required for all wells. Our standard practices include cementing above any hydrocarbon bearing zone and performing casing pressure tests to verify the integrity of the casing and cement.
- Production casing is set through the surface and intermediate casing through the depth of the targeted producing formation. Our standard practices include pumping cement above the confining structure of the target zone and performing casing pressure tests and other tests to verify the integrity of the casing and cement. If any problems are detected, then appropriate remedial action is taken.
- With the casing set and cemented, a barrier of steel and cement is in place that is designed to isolate the wellbore from surrounding geologic formations. This barrier as designed mitigates against the risk of drilling or fracturing fluids entering potential sources of drinking water.

In addition to the required use of casing and cement in the well construction, we follow additional regulatory requirements and industry operating practices. These typically include pressure testing of casing and surface equipment and continuous monitoring of surface pressure, pumping rates, volumes of fluids and chemical concentrations during hydraulic fracturing operations. When any pressure differential outside the normal range of operations occurs, pumping is shut down until the cause of the pressure differential is identified and any required remedial measures are completed. Hydraulic fracturing fluid is delivered to our sites in accordance with the U.S. Department of Transportation (DOT) regulations in DOT approved shipping containers using DOT transporters.

We also have procedures to address water use and disposal. This includes evaluating surface and groundwater sources, commercial sources, and potential recycling and reuse of treated water sources. When commercially and technically feasible, we use recycled or treated water. This practice helps mitigate against potential adverse impacts to other water supply sources. When using raw surface or groundwater, we obtain all required water rights or compensate owners for water consumption. We are evaluating additional treatment capability to augment future water supplies at several of our sites. During our drilling and completions operations, we manage waste water to minimize environmental risks and costs. Flowback water returned to the surface is typically contained in steel tanks or pits. Water that is not treated for reuse is typically piped or trucked to waste disposal injection wells, a number of which we operate. These wells are permitted through the Underground Injection Control (UIC) program of the Safe Drinking Water Act (SDWA). We also use commercial UIC permitted water injection facilities for flowback and produced water disposal.

We have not received regulatory citations or notice of suits related to our hydraulic fracturing operations for environmental concerns. We have not experienced a surface release of fluids associated with hydraulic fracturing that resulted in material financial exposure or significant environmental impact. Consistent with local, state and federal requirements, releases are reported to appropriate regulatory agencies and site restoration completed. No remediation reserve has been identified or anticipated as a result of hydraulic fracturing releases experienced to date.

Spill Prevention/Response Procedures. There are various state and federal regulations that are designed to prevent and respond to any spills or leaks resulting from exploration and production activities. In this regard, we maintain spill prevention control and countermeasures programs, which frequently include the installation and maintenance of spill containment devices

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designed to contain spill materials on location. In addition, we maintain emergency response plans to minimize potential environmental impacts in the event of a spill or leak or any significant hydraulic fracturing well control issue.

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Environmental

A description of our environmental remediation activities is included in Part II, Item 8, "Financial Statements and Supplementary Data", Note 9.

Employees

As of February 26, 2018, we had 436 full-time employees in the United States.

Executive Officers of the Registrant

In November 2017, the company announced a change in senior leadership with Russell E. Parker joining the company and becoming our President and Chief Executive Officer. He was chosen to lead a new management structure which included new team leaders Raymond J. Ambrose, Senior Vice President Engineering and Subsurface, and Chad D. England, Senior Vice President Operations, along with current Chief Financial Officer Kyle A. McCuen. In connection with the leadership change, the majority of the prior management team departed the organization. The change in senior leadership was a move from an asset-based to a function-based organizational structure, to enable greater flexibility in allocating capital and resources to specific assets, while continuing the company's focus on cost reduction and efficiencies. For more information on our new management team, please see our website at www.epenergy.com.

Our executive officers as of February 26, 2018, are listed below.

Name	Office	Age
Russell E. Parker	President, Chief Executive Officer and Director	41
Raymond J. Ambrose	Senior Vice President, Engineering and Subsurface	45
Chad D. England	Senior Vice President, Operations	38
Kyle A. McCuen	Senior Vice President, Chief Financial Officer and Treasurer	43
Jace D. Locke	Vice President, General Counsel and Corporate Secretary	41

Russell E. Parker

Mr. Parker has been our President and Chief Executive Officer and has served as a member of the Board since November 6, 2017. He was previously Chief Executive Officer of Phoenix Natural Resources LLC (Phoenix), from March 2016 to October 2017. Mr. Parker was the President of Chief Oil & Gas LLC from March 2015 to December 2015, and prior to becoming President, was Vice President of Engineering and Operations from October 2014 to March 2015 and Vice President of Engineering from November 2012 to October 2014. From January 2001 to October 2012, Mr. Parker worked in various engineering and asset management capacities for Hilcorp Energy Company (Hilcorp). Mr. Parker received his BS in Petroleum and Geosystems from the University of Texas at Austin, where he also was recognized as an Outstanding Young Graduate of the Cockrell School of Engineering as well as Distinguished Alumnus of the Petroleum Engineering Department.

Raymond J. Ambrose

Dr. Ambrose has been our Senior Vice President, Engineering and Subsurface since November 6, 2017. He was previously Senior Vice President, Engineering and Business Development for Phoenix from April 2016 to October 2017. Dr. Ambrose worked as Senior Director, Petroleum Engineering for NRG Energy, Inc., from April 2015 until joining Phoenix and as the Chief Reservoir Engineer for Hilcorp from March 2012 to March 2015. Dr. Ambrose earned a BS in chemical engineering with a petroleum minor and an MS in petroleum engineering from the University of Southern California and a PhD from the University of Oklahoma where his dissertation was focused on unconventional gas storage phenomena and rate transient analysis of unconventional reservoirs.

Chad D. England

Mr. England has been our Senior Vice President, Operations, since November 6, 2017. He was previously Senior Vice President of Operations for Phoenix from April 2016 to November 2017. Mr. England worked for Hilcorp as an Operations Manager from September 2010 to April 2016 on the Eagle Ford, Utica and South Texas asset teams. Prior to Hilcorp, he held engineering positions for ConocoPhillips from October 2006 to September 2010. Mr. England received his BS in Mechanical Engineering from Texas A&M University.

Kyle A. McCuen

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Mr. McCuen has been our Senior Vice President, Chief Financial Officer and Treasurer since January 1, 2018. He was our interim Chief Financial Officer from February 2017 to December 2017, and our Vice President and Treasurer since August 2013. He was Vice President and Treasurer of EP Energy LLC from May 2012 to August 2013. He previously served in various finance and strategic planning roles at El Paso Corporation, most recently serving as Vice President of Corporate and E&P Planning at El Paso Corporation from October 2011 to May 2012. Mr. McCuen graduated from the University of Texas with a BBA and received an MBA from the University of Houston.

Jace D. Locke

Mr. Locke has been our Vice President, General Counsel and Corporate Secretary since January 1, 2018. He was our Associate General Counsel and Assistant Secretary from August 2013 to December 2017 and was Associate General Counsel and Assistant Secretary for EP Energy LLC from May 2012 to August 2013. He previously served as Senior Counsel at El Paso Corporation from November 2007 to May 2012, which included service as Corporate Secretary of El Paso's midstream business unit. Prior to joining El Paso Corporation, Mr. Locke served as an associate at the international law firm of Dewey & LeBoeuf LLP from June 2002 to October 2007. Mr. Locke graduated from the University of Utah with a BS in Political Science and received a JD from Brigham Young University.

Available Information

Our website is http://www.epenergy.com. We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, including related exhibits and supplemental schedules, as soon as is reasonably possible after these reports are filed or furnished with the Securities and Exchange Commission (SEC). Information about each of our Board members, each of our Board's standing committee charters, and our Corporate Governance Guidelines as well as a copy of our Code of Conduct are also available, free of charge, through our website. Information contained on our website is not part of this report.

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ITEM 1A. RISK FACTORS

Risks Related to Our Business and Industry

The prices for oil, natural gas and NGLs are highly volatile and sustained lower prices have adversely affected, and may continue to adversely affect, our business, results of operations, cash flows and financial condition.

Our success depends upon the prices we receive for our oil, natural gas and NGLs. These commodity prices historically have been highly volatile and are likely to continue to be volatile in the future, especially given current global geopolitical and economic conditions. Oil and natural gas prices significantly declined in the second half of 2014, with sustained lower prices continuing throughout 2015, 2016 and 2017. There is a risk that commodity prices will remain volatile and, despite a modest recovery in late 2017, commodity prices could remain depressed for a sustained period. The prices for oil, natural gas and NGLs are subject to a variety of factors that are outside of our control, which include, among others:

- regional, domestic and international supply of, and demand for, oil, natural gas and NGLs;
- oil, natural gas and NGLs inventory levels in the United States;
- political and economic conditions domestically and in other oil and natural gas producing countries, including the current conflicts in the Middle East and conditions in Africa, Russia and South America;
- actions of OPEC and state-controlled oil companies relating to oil, natural gas and NGLs price and production controls;
- wars, terrorist activities and other acts of aggression;
- weather conditions and weather patterns;
- technological advances affecting energy consumption and energy supply;
- adoption of various energy efficiency and conservation measures and alternative fuel requirements;
- the price and availability of supplies of, and consumer demand for, alternative energy sources;
- the price and quantity of U.S. imports and exports of oil, natural gas, including liquefied natural gas, and NGLs;
- volatile trading patterns in capital and commodity-futures markets;
- the strengthening and weakening of the U.S. dollar relative to other currencies;
- changes in domestic governmental regulations, administrative and/or agency actions, and taxes, including potential restrictive regulations associated with hydraulic fracturing operations;
- changes in the costs of exploring for, developing, producing, transporting, processing and marketing oil, natural gas and NGLs;
- availability, proximity and cost of commodity processing, gathering and transportation and refining capacity;
- perceptions of customers on the availability and price volatility of our products, particularly customers' perception of the volatility of oil and natural gas prices over the longer term; and
- variations between product prices at sales points and applicable index prices.

Governmental actions may also affect oil, natural gas and NGLs prices.

The negative impact of low commodity prices on our cash flows could limit our cash available for capital expenditures and reduce our drilling opportunities. Any resulting decreases in production could result in an additional shortfall in our expected cash flows and require us to further reduce our capital spending or borrow funds to cover any such shortfall. In addition to reducing our cash flows, the prolonged and substantial decline in commodity prices has and could continue to negatively impact our proved oil and natural gas reserves and could negatively impact the amount of oil and natural gas that we can produce economically in the future. Commodity prices also affect our ability to access funds under our reserve-based revolving credit facility (the RBL Facility) and through the capital markets and may adversely affect our ability to refinance our debt. The amount available for borrowing under the RBL Facility is subject to a borrowing base, which is determined by our

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lenders taking into account our proved reserves, and is subject to periodic redeterminations (in April and November) based on pricing models determined by the lenders at such time. Declines in oil, natural gas and NGLs prices have and could continue to adversely impact the value of our proved reserves and, in turn, the bank pricing used by our lenders to determine our borrowing base. Upon redetermination, we would be required to repay amounts outstanding under our credit facility should they exceed the redetermined borrowing base. Any of these factors could further negatively impact our liquidity, our ability to replace our production and our future rate of growth. On the other hand, increases in commodity prices may be offset by increases in drilling costs, production taxes and lease operating costs that typically result from any increase in commodity prices. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

We have significant capital programs in our business that may require us to access capital markets, and any inability to obtain access to the capital markets in the future at competitive rates, or any negative developments in the capital markets, could have a material adverse effect on our business.

We have significant capital programs in our business, which may require us to access the capital markets. Since we are rated below investment grade, our ability to access the capital markets or the cost of capital could be negatively impacted in the future, which could require us to forego capital opportunities or could make us less competitive in our pursuit of growth opportunities, especially in relation to many of our competitors that are larger than us or have investment grade ratings. There is a risk that our below investment credit rating may be further adversely affected in the future as the credit rating agencies review their general credit requirements in light of the sustained lower commodity price environment as well as review our leverage, liquidity, credit profile and potential transactions. Reductions in our credit rating could have a negative impact on us. For example, a lower credit rating could limit our available liquidity if we are required to post incremental collateral on transportation contract obligations or other contractual commitments.

In addition, the credit markets for companies in the energy sector in recent years have experienced a period of turmoil and upheaval as commodity prices have been volatile. These circumstances and events have led to reduced credit availability, tighter lending standards and higher interest rates on loans for companies in the energy industry, especially non-investment grade companies. While we cannot predict the future condition of the credit markets, future turmoil in the credit markets could have a material adverse effect on our business, liquidity, financial condition and cash flows, particularly if our ability to borrow money from lenders or access the capital markets to finance our operations were to be impaired. Our primary source of liquidity beyond cash flow from operations is our RBL Facility. At December 31, 2017, we had $595 million outstanding under the facility and a borrowing base of $1.4 billion. In January 2018, as a result of exchanging $954 million, $54 million and $139 million of the outstanding amount of our senior unsecured notes maturing in May 2020, September 2022 and June 2023, respectively, the borrowing base was reduced to $1.36 billion.

Although we believe that the banks participating in the RBL Facility have adequate capital and resources, we can provide no assurance that all of those banks will continue to operate as going concerns in the future, or continue to participate in the facility. If any of the banks in our lending group were to fail, or choose not to participate, it is possible that the borrowing capacity under the RBL Facility would be reduced. In the event of such reduction, we could be required to obtain capital from alternate sources or find additional RBL participants in order to finance our capital needs. Our options for addressing such capital constraints would include, but not be limited to, obtaining commitments from the remaining banks in the lending group or from new banks to fund increased amounts under the terms of the RBL Facility, and accessing the public and private capital markets. In addition, we may delay certain capital expenditures to ensure that we maintain appropriate levels of liquidity. If it became necessary to access additional capital, any such alternatives could have terms less favorable than the current terms under the RBL Facility, which could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Our substantial indebtedness could adversely affect our ability to raise additional capital to fund our operations, limit our ability to react to changes in the economy or our industry and require us to dedicate a substantial portion of cash flows to service our debt payment obligations.

We are a highly leveraged company with significant debt and debt service obligations. Our substantial indebtedness could:

- require us to dedicate a substantial portion of our cash flow from operations to debt service payments thereby reducing the availability of cash for working capital, capital expenditures, acquisitions or general corporate purposes;
- limit our ability to borrow money for our working capital, capital expenditures, debt service requirements, strategic initiatives or other purposes;

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- expose us to more liquidity risks, including breach of covenants and default risks, especially during times of financial and commodity price volatility;
- make us more vulnerable to downturns in our business or the economy;
- limit our flexibility in planning for, or reacting to, changes in our operations or business;
- increase our leverage relative to our competitors, which may place us at a competitive disadvantage;
- restrict us from making strategic acquisitions, engaging in development activities, introducing new technologies or exploiting business opportunities;
- cause us to make non-strategic divestitures; or
- cause us to issue equity thereby diluting existing stockholders.

The success of our business depends upon our ability to find and replace reserves that we produce.

Similar to our competitors, we have a reserve base that is depleted as it is produced. Unless we successfully replace the reserves that we produce, our reserves will decline, which will eventually result in a decrease in oil and natural gas production and lower revenues and cash flows from operations. We historically have replaced reserves through both drilling and acquisitions. The business of exploring for, developing or acquiring reserves requires substantial capital expenditures. If we do not continue to make significant capital expenditures (for any reason, including our access to capital resources becoming limited) or if our exploration, development and acquisition activities are unsuccessful, we may not be able to replace the reserves that we produce, which would negatively impact us. As a result, our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs or at all. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, results of operations and financial condition would be materially adversely affected.

Our oil and natural gas drilling and producing operations involve many risks, and our production forecasts may differ from actual results.

Our success will depend on our drilling results. Our drilling operations are subject to the risk that (i) we may not encounter commercially productive reservoirs or (ii) if we encounter commercially productive reservoirs, we either may not fully recover our investments or our rates of return will be less than expected. Our past performance should not be considered indicative of future drilling performance. As a result, there remains uncertainty on the results of our drilling programs, including our ability to realize proved reserves or to earn acceptable rates of return on our drilling programs. From time to time, we provide forecasts of expected quantities of future production. These forecasts are based on a number of estimates, including expectations of production from existing wells and the outcome of future drilling activity. Our forecasts could be different from actual results and such differences could be material.

Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. In addition, the results of our exploratory drilling in new or emerging areas are more uncertain than drilling results in areas that are developed and have established production. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economic than forecasted. Further, many factors may increase the cost of, or curtail, delay or cancel drilling operations, including the following:

- unexpected drilling conditions;
- delays imposed by or resulting from compliance with regulatory and contractual requirements, including requirements on sourcing of materials;
- unexpected pressure or irregularities in geological formations;
- equipment failures or accidents;
- fracture stimulation accidents or failures;
- adverse weather conditions;

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- declines in oil and natural gas prices;
- surface access restrictions with respect to drilling or laying pipelines;
- shortages (or increases in costs) of water used in hydraulic fracturing, especially in arid regions or regions that have been experiencing severe drought conditions;
- shortages or delays in the availability of, increases in the cost of, or increased competition for, drilling rigs and crews, fracture stimulation crews, equipment, pipe, chemicals and supplies and transportation, gathering, processing, treating or other midstream services; and
- limitations or reductions in the market for oil and natural gas.

Additionally, the occurrence of certain of these events, particularly equipment failures or accidents, could impact third parties, including persons living in proximity to our operations, our employees and employees of our contractors, leading to possible injuries or death or significant property damage. As a result, we face the possibility of liabilities from these events that could materially adversely affect our business, results of operations and financial condition.

In addition, uncertainties associated with enhanced recovery methods may not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate and we may be unable to realize an acceptable return on our investments in certain of our projects. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict.

Our drilling locations are scheduled to be drilled over a number of years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has identified and scheduled potential drilling locations as an estimate of our future multi-year drilling activities on our existing acreage. All of our potential drilling locations, particularly our potential drilling locations for oil, represent a significant part of our strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil, natural gas and NGLs prices, costs and drilling results. Because of these uncertainties, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells where a final investment decision has been made to drill within five years of the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Drilling locations that we decide to drill may not yield oil, natural gas or NGLs in commercially viable quantities.

Our future drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively, prior to drilling, whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil, natural gas or NGLs exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our other identified drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. The cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

We require substantial capital expenditures to conduct our operations, engage in acquisition activities and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy.

We require substantial capital expenditures to conduct our exploration, development and production operations, engage in acquisition activities and increase our proved reserves and production. In 2017, we spent total capital of $587 million. We have established a capital budget for 2018 of approximately $600 million to $650 million (not including acquisition capital) and we intend to rely on cash flow from operating activities and available cash and borrowings under the RBL Facility as our primary sources of liquidity. For a discussion of liquidity, see Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources”. We also may engage in asset sale transactions to, among other things, fund capital expenditures when market conditions permit us to complete transactions on

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terms we find acceptable. There can be no assurance that such sources will be available to us or sufficient to fund our exploration, development and acquisition activities. If our revenues and cash flows continue to decrease in the future as a result of sustained declines in commodity prices or a reduction in production levels, and we are unable to obtain additional equity or debt financing in the capital markets or access alternative sources of funds, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to increase or even maintain our reserves and production levels.

Our future revenues, cash flows and spending levels are subject to a number of factors, including commodity prices, the level of production from existing wells and our success in developing and producing new wells. Further, our ability to access funds under the RBL Facility is based on a borrowing base, which is subject to periodic redeterminations (in April and November) based on our proved reserves and pricing models that will be determined by our lenders at such time. If the prices for oil and natural gas decline, if we have a downward revision in estimates of our proved reserves, or if we sell additional oil and natural gas reserves, our borrowing base may be reduced.

Our ability to access the capital markets and complete future asset monetization transactions is also dependent upon oil, natural gas and NGLs prices, in addition to a number of other factors, some of which are outside our control. These factors include, among others, domestic and global economic conditions and conditions in the domestic and global financial markets.

Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, take advantage of business opportunities, respond to competitive pressures or refinance our debt obligations as they come due, any of which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our use of derivative financial instruments could result in financial losses or could reduce our income.

We use fixed price financial options and swaps to mitigate our commodity price and basis exposures. However, we do not typically hedge all of these exposures, and typically do not hedge any of these exposures beyond several years. Our derivative contracts (primarily fixed price derivatives) as of December 31, 2017, will allow us to realize a weighted average price of $58.68 per barrel on 13.6 MMBbls of oil and $3.04 per MMBtu on 26 TBtu of natural gas in 2018 and a weighted average price of $2.97 per MMBtu on 7 TBtu of natural gas in 2019. We have limited price protection in 2019 and none past this timeframe. As a result, we have substantial commodity price and basis exposure since our business has multi-year drilling programs for our proved reserves and unproved resources, particularly as our existing hedges roll off.

The derivative contracts we enter into to mitigate commodity price risk are not designated as accounting hedges and are therefore marked to market. As a result, we experience volatility in our revenues and net income as a result of changes in commodity prices, counterparty non-performance risks, correlation factors and changes in the liquidity of the market. Furthermore, the valuation of these financial instruments involves estimates that are based on assumptions that could prove to be incorrect and result in financial losses. Although we have internal controls in place that impose restrictions on the use of derivative instruments, there is a risk that such controls will not be complied with or will not be effective, and we could incur substantial losses on our derivative transactions. The use of derivatives, to the extent they require collateral posting with our counterparties, could impact our working capital and liquidity when commodity prices or interest rates change.

To the extent we enter into derivative contracts to manage our commodity price and basis exposures, we may forego the benefits we could otherwise experience if such prices were to change favorably and we could experience losses to the extent that these prices were to increase above the fixed price. In addition, these hedging arrangements also expose us to the risk of financial loss in the following circumstances, among others:

- when production is less than expected or less than we have hedged;
- when the counterparty to the hedging instrument defaults on its contractual obligations;
- when there is an increase in the differential between the underlying price in the hedging instrument and actual prices received; and
- when there are issues with respect to legal enforceability of such instruments.

Our derivative counterparties are typically large financial institutions. We are subject to the risk of loss on our derivative instruments as a result of non-performance by counterparties to the terms of their obligations. The risk that a counterparty may default on its obligations is heightened when there is a significant decline in commodity prices. The ability of our counterparties to meet their obligations to us on hedge transactions could reduce our revenue from hedges at a time when we are also receiving a lower price for our oil and natural gas sales. As a result, our business, results of operations and financial condition could be materially adversely affected.

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Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.
The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) provided for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandated that the Commodity Futures Trading Commission (the CFTC), the SEC and certain federal regulators of financial institutions (the Prudential Regulators) adopt rules or regulations to implement the Dodd-Frank Act and provide definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act established margin requirements and required clearing and trade execution practices for certain market participants and resulted in certain market participants curtailing and/or ceasing their derivatives activities.

Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including a rule (the Mandatory Clearing Rule) requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have), a rule establishing an "end user" exception (the End User Exception) to the Mandatory Clearing Rule, a rule (the Margin Rule) setting forth collateral requirements in connection with swaps that are not cleared and also an exception (the Non-Financial End User Exception) to the Margin Rule for end users that are not financial end users and a rule (the Position Limit Rule), subsequently vacated by the United States District Court for the District of Columbia and remanded to the CFTC for further proceedings, imposing position limits. The CFTC proposed a new version of the Position Limit Rule, with respect to which the comment period closed but no final rule was issued, and has re-proposed a new version of the Position Limit Rule (the Re-Proposed Position Limit Rule) with respect to which the comment period is scheduled to close on February 28, 2017. The Re-Proposed Position Limit Rule provides an exemption from the position limits for swaps that constitute “bona fide hedging positions” within the definition of such term under the Re-Proposed Position Limit Rule, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of the Re-Proposed Position Limit Rule.

We qualify for the End User Exception and will utilize it if the Mandatory Clearing Rule is expanded to cover swaps in which we participate, we qualify for the Non-Financial End User Exception and will not be required to post margin under the Margin Rule and our existing and anticipated hedging positions constitute “bona fide hedging positions” under the Re-Proposed Position Limit Rule and we intend to do the filing, recordkeeping and reporting necessary to utilize the bona fide hedging position exemption under the Re-Proposed Position Limit Rule if and when it becomes effective, so we do not expect to be directly affected by any of such rules. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End User Exception and will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception or another exception to the Margin Rule. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (collectively, Foreign Regulations, including laws and regulations giving European Union financial authorities the power to write down amounts we may be owed on hedging agreements with counterparties subject to such Foreign Regulations and/or require that we accept equity interests in such counterparties in lieu of cash in satisfaction of such amounts) which may apply to our transactions with counterparties subject to such Foreign Regulations. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule is ultimately effected, such proposed rule could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. The Foreign Regulations could have similar effects. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations and Foreign Regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

Estimating our reserves involves uncertainty, our actual reserves will likely vary from our estimates, and negative revisions to our reserve estimates in the future could result in decreased earnings and/or losses and impairments.

All estimates of proved reserves are determined according to the rules prescribed by the SEC. Our reserve information is prepared internally and is audited by an independent petroleum engineering consultant. There are numerous uncertainties involved in estimating proved reserves, which may result in our estimates varying considerably from actual

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results. Estimating quantities of proved reserves is complex and involves significant interpretation and assumptions with respect to available geological, geophysical and engineering data, including data from nearby producing areas. It also requires us to estimate future economic factors, such as commodity prices, production costs, plugging and abandonment costs, severance, ad valorem and excise taxes, capital expenditures, workover and remedial costs, and the assumed effect of governmental regulation. Due to a lack of substantial production data, there are greater uncertainties in estimating proved undeveloped reserves and proved developed non-producing reserves. There is also greater uncertainty of estimating proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise. Furthermore, estimates are subject to revision based upon a number of factors, including many factors beyond our control such as reservoir performance, prices (including commodity prices and the cost of oilfield services), economic conditions and government restrictions and regulations. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Therefore, our reserve information represents an estimate and is often different from the quantities of oil and natural gas that are ultimately recovered or proven recoverable.

The SEC rules require the use of a 10% discount factor for estimating the value of our future net cash flows from reserves and the use of a historical 12-month average price. This discount factor may not necessarily represent the most appropriate discount factor, given our costs of capital, actual interest rates and risks faced by our exploration and production business, and the average historical price will not generally represent the future market prices for oil and natural gas over time. Any significant change in commodity prices could cause the estimated quantities and net present value of our reserves to differ and these differences could be material. You should not assume that the present values referred to in this Annual Report on Form 10-K represent the current market value of our estimated oil and natural gas reserves. Finally, the timing of the production and the expenses related to the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value.

We account for our activities under the successful efforts method of accounting. Changes in the estimated fair value of these reserves could result in a write-down in the carrying value of our oil and natural gas properties, which could be substantial and could have a material adverse effect on our net income and stockholders' equity. Lower estimated fair value of these reserves could also result in lower recorded reserves, which would increase our depreciation, depletion and amortization rates and decrease earnings.

A portion of our proved reserves are undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. In addition, because our proved reserve base consists primarily of unconventional resources, the costs of finding, developing and producing those reserves may require capital expenditures that are greater than more conventional resource plays. Our estimates of proved reserves assume that we can and will make these expenditures and conduct these operations successfully. However, future events, including commodity price changes and our ability to access capital markets, may cause these assumptions to change.

Our business is subject to competition from third parties, which could negatively impact our ability to succeed.

The oil, natural gas and NGLs businesses are highly competitive. We compete with third parties in the search for and acquisition of leases, properties and reserves, as well as the equipment, materials and services required to explore for and produce our reserves. There has been intense competition for the acquisition of leasehold positions, particularly in many of the oil and natural gas shale plays. 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 fund and consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil properties. Similarly, we compete with many third parties in the sale of oil, natural gas and NGLs to customers, some of which have substantially larger market positions, marketing staff and financial resources than us. Our competitors include major and independent oil and natural gas companies, as well as financial services companies and investors, many of which have financial and other resources that are substantially greater than those available to us. Many of these companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices.

Furthermore, there is significant competition between the oil and natural gas industry and other industries producing energy and fuel, which may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by federal, state and local governments. It is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or

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continuation of a given operation. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which could negatively impact our competitive position.

Our industry is cyclical, and at certain times historically there have been shortages of drilling rigs, equipment, supplies or qualified personnel. A sustained decline in commodity prices can also reduce the number of service providers for such drilling rigs, equipment, supplies or qualified personnel, contributing to or also resulting in the shortages. Alternatively, during periods of high prices, the cost of rigs, equipment, supplies and personnel can fluctuate widely and availability may be limited. These services may not be available on commercially reasonable terms or at all. We cannot predict the extent to which these conditions will exist in the future or their timing or duration. The high cost or unavailability of drilling rigs, equipment, supplies, personnel and other oil field services could significantly decrease our profit margins, cash flows and operating results and could restrict our ability to drill the wells and conduct the operations that we currently have planned and budgeted or that we may plan in the future. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

Our business is subject to operational hazards and uninsured risks that could have a material adverse effect on our business, results of operations and financial condition.

Our oil and natural gas exploration and production activities are subject to all of the inherent risks associated with drilling for and producing natural gas and oil, including the possibility of:

- Adverse weather conditions, natural disasters, and/or other climate related matters—including extreme cold or heat, lightning and flooding, severe drought, fires, earthquakes, hurricanes, tropical storms, tornadoes and other natural disasters. Although the potential effects of climate change on our operations (such as hurricanes, flooding, etc.) are uncertain at this time, changes in climate patterns could also have a negative impact upon our operations in the future, particularly with regard to any of our facilities that are located in or near coastal regions;
- Acts of aggression on critical energy infrastructure—including terrorist activity or “cyber security” events. We are subject to the ongoing risk that one of these incidents may occur which could significantly impact our business operations and/or financial results. Should one of these events occur in the future, it could impact our ability to operate our drilling and exploration processes, our operations could be disrupted, and/or property could be damaged resulting in substantial loss of revenues, increased costs to respond or other financial loss, damage to reputation, increased regulation and litigation and/or inaccurate information reported from our exploration and production operations to our financial applications, to our customers and to regulatory entities; and
- Other hazards—including the collision of third-party equipment with our infrastructure; explosions, equipment malfunctions, mechanical and process safety failures, well blowouts, formations with abnormal pressures and collapses of wellbore casing or other tubulars; events causing our facilities to operate below expected levels of capacity or efficiency; uncontrollable flows of natural gas, oil, brine or well fluids, release of pollution or contaminants (including hydrocarbons) into the environment (including discharges of toxic gases or substances) and other environmental hazards.

Each of these risks could result in (i) damage to and destruction of our facilities; (ii) damage to and destruction of property, natural resources and equipment; (iii) injury or loss of life; (iv) business interruptions while damaged energy infrastructure is repaired or replaced; (v) pollution and other environmental damage; (vi) regulatory investigations and penalties; and (vii) repair and remediation costs. Any of these results could cause us to suffer substantial losses.

While we maintain insurance against some of these risks in amounts that we believe are reasonable, our insurance coverages have material deductibles, self-insurance levels and limits on our maximum recovery and do not cover all risks. For example, from time to time, we may not carry, or may be unable to obtain, on terms that we find acceptable and/or reasonable, insurance coverage for certain exposures, including, but not limited to certain environmental exposures (including potential environmental fines and penalties), business interruption and named windstorm/hurricane exposures and, in limited circumstances, certain political risk exposures. The premiums and deductibles we pay for certain insurance policies are also subject to the risk of substantial increases over time that could negatively impact our financial results. In addition, we may not be able to renew existing insurance policies or procure desirable insurance on commercially reasonable terms. There is also a risk that our insurers may default on their insurance coverage obligations or that amounts for which we are insured, or that the proceeds of such insurance, will not compensate us fully for our losses. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

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Some of our operations are subject to joint ventures or operations by third parties, which could negatively impact our control over these operations and have a material adverse effect on our business, results of operations, financial condition and prospects.

A small portion of our operations and interests are operated by third-party working interest owners. In such cases, (i) we have limited ability to influence or control the day-to-day operation of such properties, including compliance with environmental, safety and other regulations, (ii) we cannot control the amount of capital expenditures that we are required to fund with respect to properties, (iii) we are dependent on third parties to fund their required share of capital expenditures and (iv) we may have restrictions or limitations on our ability to sell our interests in these jointly owned assets.

The insolvency of an operator of our properties, the failure of an operator of our properties to adequately perform operations or an operator’s breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner. As a result, the success and timing of our drilling and development activities on properties operated by others and the economic results derived therefrom depends upon a number of factors outside of our control, including the operator’s timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Finally, an operator of our properties may have the right, if another non-operator fails to pay its share of costs, to require us to pay our proportionate share of the defaulting party's share of costs.

We currently sell most of our oil production to a limited number of significant purchasers. The loss of one or more of these purchasers, if not replaced, could reduce our revenues and have a material adverse effect on our financial condition or results of operations.

For the year ended December 31, 2017, eleven purchasers accounted for approximately 89% of our oil revenues. We depend upon a limited number of significant purchasers for the sale of most of our production. The loss of any of these customers, should we be unable to replace them, could adversely affect our revenues and have a material adverse effect on our financial condition and results of operations. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have access to suitably liquid markets for our future production.

We are subject to a complex set of laws and regulations that regulate the energy industry for which we have to incur substantial compliance and remediation costs.

Our operations, and the energy industry in general, are subject to a complex set of federal, state and local laws and regulations over the following activities, among others:

- the location of wells;
- methods of drilling and completing wells;
- allowable production from wells;
- unitization or pooling of oil and gas properties;
- spill prevention plans;
- limitations on venting or flaring of natural gas;
- disposal of fluids used and wastes generated in connection with operations;
- access to, and surface use and restoration of, well properties;
- plugging and abandoning of wells, even if we no longer own and/or operate such wells;
- air quality and emissions, noise levels and related permits;
- gathering, transportation and marketing of oil and natural gas (including NGLs);
- taxation;
- competitive bidding rules on federal and state lands; and
- the sourcing and supply of materials needed to operate.

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Generally, the regulations have become more stringent and have imposed more limitations on our operations and, as a result, have caused us to incur more costs to comply. Many required approvals are subject to considerable discretion by the regulatory agencies with respect to the timing and scope of approvals and permits issued. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned or at all. Delays in obtaining regulatory approvals or permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with excessive conditions or costs could have a material negative impact on our operations and financial results. We may also incur substantial costs in order to maintain compliance with these existing laws and regulations, including costs to comply with new and more extensive reporting and disclosure requirements. Failure to comply with such requirements may result in the suspension or termination of operations and may subject us to criminal as well as civil and administrative penalties. We are exposed to fines and penalties to the extent that we fail to comply with the applicable laws and regulations, as well as the potential for limitations to be imposed on our operations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Also, some of our assets are located and operate on federal, state, local or tribal lands and are typically regulated by one or more federal, state or local agencies. For example, we have drilling and production operations that are located on federal lands, which are regulated by the DOI, particularly by the Bureau of Land Management (BLM). We also have operations on Native American tribal lands, which are regulated by the DOI, particularly by the Bureau of Indian Affairs (BIA), as well as local tribal authorities. Operations on these properties are often subject to additional regulations and compliance obligations, which can delay our access to such lands and impose additional compliance costs. There are also various laws and regulations that regulate various market practices in the industry, including antitrust laws and laws that prohibit fraud and manipulation in the markets in which we operate. The authority of the Federal Trade Commission and the CFTC to impose penalties for violations of laws or regulations has generally increased over the last few years.

We are exposed to the credit risk of our counterparties, contractors and suppliers.

We have significant credit exposure related to our sales of physical commodities, payments to contractors and suppliers, hedging activities and to the non-operating working interest owners who are counterparties to our operating agreements. If our counterparties become insolvent or otherwise fail to make payments/or perform within the time required under our contracts, our results of operations and financial condition could be materially adversely affected. Although we maintain strict credit policies and procedures and credit insurance in some cases, they may not be adequate to fully eliminate the credit risk associated with our counterparties, contractors and suppliers.

We are exposed to the performance risk of our key contractors and suppliers.

As an owner of drilling and production facilities with significant capital expenditures in our business, we rely on contractors for certain construction, drilling and completion operations and we rely on suppliers for key materials, supplies and services, including steel mills, pipe and tubular manufacturers and oil field service providers. We also rely upon the services of other third parties to explore or analyze our prospects to determine a method in which the prospects may be developed in a cost-effective manner. There is a risk that such contractors and suppliers may experience credit and performance issues triggered by a sustained low or a volatile commodity price environment that could adversely impact their ability to perform their contractual obligations with us, including their performance and warranty obligations. This could result in delays or defaults in performing such contractual obligations and increased costs to seek replacement contractors, each of which could negatively impact us. We could also be exposed to liability that we would otherwise be indemnified for by these counterparties should they become insolvent or are otherwise unable to satisfy their obligations under their indemnities.

The Sponsors and other legacy investors own approximately 83 percent of the equity interests in us and may have conflicts of interest with us and or public investors.

Investment funds affiliated with, and one or more co-investment vehicles controlled by, our Sponsors (affiliates of Apollo Global Management LLC, Riverstone Holdings LLC, Access Industries and Korea National Oil Corporation, collectively the Sponsors) and other legacy investors collectively own approximately 83 percent of our equity interests and such persons or their designees hold substantially all of the seats on our board of directors. As a result, the

Sponsors and such other investors have control over our decisions to enter into certain corporate transactions and have the ability to prevent any transaction that typically would require the approval of stockholders, regardless of whether holders of our notes or stock believe that any such transactions are in their own best interests. For example, the Sponsors and other legacy investors could collectively cause us to make acquisitions that increase the amount of our indebtedness or to sell assets, or could cause us to issue additional equity, debt, or declare dividends or other distributions to our equity holders. So long as investment funds affiliated with the Sponsors and other such investors continue to indirectly own a majority of the outstanding shares of our equity interests or otherwise control a majority of our board of directors, these investors will continue to be able to strongly influence or effectively control our decisions. The indentures governing the notes and the credit agreements governing the RBL Facility and our senior secured term loan permit us, under certain circumstances, to pay advisory and other fees, pay dividends and make other restricted payments to the Sponsors and other investors, and the Sponsors and such other investors or their respective affiliates may have an interest in our doing so.

Additionally, the Sponsors and other legacy investors are in the business of making investments in companies and may from time to time acquire and hold interests in businesses that compete directly or indirectly with us or that supply us with goods and services. These persons may also pursue acquisition opportunities that may be complementary to (or competitive with) our business, and as a result those acquisition opportunities may not be available to us. In addition, the Sponsors' and other investors' interests in other portfolio companies could impact our ability to pursue acquisition opportunities.

The loss of the services of key personnel could have a material adverse effect on our business.

Our executive officers and other members of our senior management have substantial experience and expertise in our business and industry. We do not have key man or similar life insurance covering our executive officers and other members of senior management. The unexpected loss of services of one or more of our executive officers or members of senior management could have a material adverse effect on our business.

Our business requires the retention and recruitment of a skilled workforce and the loss of employees and skilled labor shortages could result in the inability to implement our business plans and could negatively impact our profitability.

Our business requires the retention and recruitment of a skilled workforce including engineers, technical personnel, geoscientists, project managers, land personnel and other professionals. We compete with other companies in the energy and other industries for this skilled workforce. We have developed company-wide compensation and benefit programs that are designed to be competitive among our industry peers and that reflect market-based metrics as well as incentives to create alignment with the Sponsors and other investors, but there is a risk that these programs and those in the future will not be successful in retaining and recruiting these professionals or that we could experience increased costs. If we are unable to (i) retain our current employees, (ii) successfully complete our knowledge transfer and/or (iii) recruit new employees of comparable knowledge and experience, our business, results of operations and financial condition could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

We may be affected by skilled labor shortages, which we have from time-to-time experienced. There is also a risk that staff reductions, that have and may continue to accompany the downturn in the industry, may adversely impact our ability to conduct our business or respond to new business opportunities. Skilled labor shortages could negatively impact the productivity and profitability of certain projects. Our inability to bid on new and attractive projects, or maintain productivity and profitability on existing projects due to the limited supply of skilled workers and/or increased labor costs could have a material adverse effect on our business, results of operation and financial condition.

Our strategy involves drilling in shale plays using some of the latest available horizontal drilling and completion techniques, the results of which are subject to drilling and completion technique risks, and drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing the latest horizontal drilling and completion techniques in order to maximize cumulative recoveries and therefore optimize our returns. Drilling risks that we face include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently longer period. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

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New technologies may cause our current exploration and drilling methods to become obsolete.

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our business, results of operations and financial condition may be materially adversely affected.

Our business depends on access to oil, natural gas and NGLs processing, gathering and transportation systems and facilities.

The marketability of our oil, natural gas and NGLs production depends in large part on the operation, availability, proximity, capacity and expansion of processing, gathering and transportation facilities owned by third parties. We can provide no assurance that sufficient processing, gathering and/or transportation capacity will exist or that we will be able to obtain sufficient processing, gathering and/or transportation capacity on economic terms. A lack of available capacity on processing, gathering and transportation facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these facilities for an extended period of time could negatively impact our revenues. In addition, we have entered into contracts for firm transportation and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water currently is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. In times of drought, we may be subject to local or state restrictions on the amount of water we procure to help protect local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce our reserves, which could have an adverse effect on our financial condition, results of operations and cash flows.

We may face unanticipated water and other waste disposal costs.

We may be subject to regulation that restricts our ability to discharge water produced as part of our operations. Productive zones frequently contain water that must be removed in order for the oil and natural gas to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce oil and natural gas in commercial quantities. The produced water must be transported from the lease and injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our oil and natural gas wells may affect our ability to produce our oil and natural gas wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability.

Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, our wells produce water in excess of the applicable volumetric permit limits, the disposal wells fail to meet the requirements of all applicable regulatory agencies, or we are unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water;
- new laws and regulations require water to be disposed in a different manner; or
- costs to transport the produced water to the disposal wells increase.

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Our acquisition attempts may not be successful or may result in completed acquisitions that do not perform as anticipated.

We have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable or at all. Any acquisition, including any completed or future acquisition, involves potential risks, including, among others:

- we may not produce revenues, reserves, earnings or cash flow at anticipated levels or could have environmental, permitting or other problems for which contractual protections prove inadequate;
- we may assume liabilities that were not disclosed to us and for which contractual protections prove inadequate or that exceed our estimates;
- we may acquire properties that are subject to burdens on title that we were not aware of at the time of acquisition that interfere with our ability to hold the property for production and for which contractual protections prove inadequate;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- we may encounter disruptions to our ongoing business and matters that distract our management or divert resources that make it difficult to maintain our current business standards, controls, procedures and policies;
- we may issue (or assume) additional equity or debt securities or debt instruments in connection with future acquisitions, which may affect our liquidity or financial leverage;
- we may make mistaken assumptions about costs, including synergies related to an acquired business;
- we may encounter difficulties in complying with regulations, such as environmental regulations, and managing risks related to an acquired business;
- we may encounter limitations on rights to indemnity from the seller;
- we may make mistaken assumptions about the overall costs of equity or debt used to finance any such acquisition;
- we may encounter difficulties in entering markets in which we have no or limited direct prior experience and where competitors in such markets have stronger expertise and/or market positions;
- we may potentially lose key customers; and
- we may lose key employees and/or encounter costly litigation resulting from the termination of those employees.

Any of the above risks could significantly impair our ability to manage our business, complete or effectively integrate acquisitions and may have a material adverse effect on our business, results of operations and financial condition.

Certain of our undeveloped leasehold acreage is subject to leases that will expire in several years unless production is established on units containing the acreage.

Although many of our reserves are located on leases that are held-by-production or held by continuous development, we do have provisions in a number of our leases that provide for the lease to expire unless certain conditions are met, such as drilling having commenced on the lease or production in paying quantities having been obtained within a defined time period. If commodity prices remain low or we are unable to allocate sufficient capital to meet these obligations, there is a risk that some of our existing proved reserves and some of our unproved inventory/acreage could be subject to lease expiration or a requirement to incur additional leasehold costs to extend the lease. This could result in impairment of remaining costs, a reduction in our reserves and our growth opportunities (or the incurrence of significant costs) and therefore could have a material adverse effect on our financial results.

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If oil and/or natural gas prices decrease, we may be required to take write-downs of the carrying values of our properties, which could result in a material adverse effect on our results of operations and financial condition.
Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for impairment. Under the successful efforts method of accounting, we review our oil and natural gas properties upon a triggering event (such as a significant and sustained decline in forward commodity prices or a significant change in current and anticipated allocated capital) to determine if impairment of such properties is necessary. Significant undeveloped leasehold costs are assessed for impairment at a lease level or resource play level based on our current exploration plans, while leasehold acquisition costs associated with prospective areas that have limited or no previous exploratory drilling are generally assessed for impairment by major prospect area. Proved oil and natural gas property values are reviewed when circumstances suggest the need for such a review and may occur if actual discoveries in a field are lower than anticipated reserves, reservoirs produce below original estimates or if commodity prices fall to a level that significantly affects anticipated future cash flows on the property. If required, the proved properties are written down to their estimated fair market value based on proved reserves and other market factors.
As of December 31, 2017, our estimated reserves are based on the average first day of the month spot price for the preceding 12-month period of $51.34 per barrel of oil (which is below the forward strip price as of December 31, 2017) and $2.98 per MMBtu of natural gas, as required by the SEC Regulation S-X, Rule 4-10 as amended. We may incur impairment charges on our proved property in the future depending on the fair value of our proved reserves, which are subject to change as a result of factors such as prices, costs and well performance. We could also incur significant impairment charges of our unproved property should low oil prices not justify sufficient capital allocation to the continued development of our unproved properties, among other factors. These impairment charges could have a material adverse effect on our results of operations and financial condition for the periods in which such charges are taken.
Sector cost inflation could adversely affect our profitability, cash flows and ability to execute our development plans as scheduled and on budget.
Historically, our capital and operating costs have risen during periods of increasing oil and natural gas prices. In particular, decreased levels of drilling activity in the oil and gas industry in recent years led to declining costs of some oilfield services and supplies. However, during 2017, increases in U.S. onshore drilling and completion activity resulted in higher demand for oilfield services and supplies. As a result, the costs of drilling, equipping and operating wells and infrastructure began to experience some inflation. If this trend continues, and if the commodity price recovery is robust, we expect industry exploration and production activities to continue to increase, resulting in even higher demand for oilfield services and supplies, which could result in significant sector price inflation. Such costs may rise faster than our revenues increase, which could negatively impact our profitability, cash flows and ability to execute our development plans as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

Our operations are subject to governmental laws and regulations relating to environmental matters, which may expose us to significant costs and liabilities and could exceed current expectations.
Our business is subject to laws and regulations that govern environmental matters. These regulations include compliance obligations for air emissions, water quality, wastewater discharge and solid and hazardous waste disposal, spill prevention, control and countermeasures, as well as regulations designed for the protection of threatened or endangered species. In some cases, our operations are subject to federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to state regulations relating to conservation practices and protection of correlative rights. These regulations may negatively impact our operations and limit the quantity of natural gas and oil we produce and sell. We must take into account the cost of complying with such requirements in planning, designing, constructing, drilling, operating and abandoning wells and related surface facilities, including gathering, transportation, storage and waste disposal facilities. The regulatory frameworks govern, and often require permits for, the handling of drilling and production materials, water withdrawal, disposal of produced water, drilling and production wastes, operation of air emissions sources, and drilling activities, including

those conducted on lands lying within wilderness, wetlands, ecologically or seismically sensitive areas, Federal and Indian lands and other protected areas. Various governmental authorities, including the U.S. Environmental Protection Agency (EPA), the DOI, the BIA and analogous state agencies and tribal governments, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions, such as installing and maintaining pollution controls and maintaining measures to address personnel and process safety and protection of the environment and animal habitat near our operations. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases. Liabilities, penalties, suspensions, terminations and increased costs resulting from any failure to comply with regulations and requirements of the type described above, or from the enactment of additional similar regulations or requirements in the future or a change in the interpretation or the enforcement of existing regulations or requirements of this type, could have a material adverse effect on our business, results of operations and financial condition.

Legislation and regulatory initiatives intended to address pipeline safety could increase our operating costs.

Gas pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation (DOT), and various other federal, state and local agencies. Congress has enacted several pipeline safety acts over the years. Currently, the Pipeline and Hazardous Materials Safety Administration (PHMSA) under DOT administers pipeline safety requirements for natural gas and hazardous liquid pipelines. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules. In June 2016, Congress approved new pipeline safety legislation, the “Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016” (the “PIPES Act”), which provides the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions, and safety measures on owners and operators of gas or hazardous liquids pipeline facilities. Significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the current pipeline control system capabilities.

Recently, the PHMSA has proposed additional regulations for gas pipeline safety. For example, in March 2016, the PHMSA proposed a rule that would expand integrity management requirements beyond High Consequence Areas to gas pipelines in newly defined Moderate Consequence Areas. The public comment period closed in July 2016. Also, in January 2017, the PHMSA released an advance copy of its final rules to expand its safety regulations for hazardous liquid pipelines by, among other things, expanding the required use of leak detection systems, requiring more frequent testing for corrosion and other flaws, and requiring companies to inspect pipelines in areas affected by extreme weather or natural disasters. The final rule was withdrawn by the PHMSA in January 2017, and it is unclear whether and to what extend the PHMSA will move forward with its regulatory reforms.

Regulation relating to climate change and energy conservation could result in increased operating costs and reduced demand for oil and natural gas we produce.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climate changes. In response to its endangerment finding, the EPA has adopted regulations restricting emissions of GHGs from motor vehicles and certain large stationary sources. The EPA adopted the stationary source rule, also known as the “Tailoring Rule,” in May 2010, and it also became effective January 2011, although the U.S. Supreme Court partially invalidated the rule in an opinion issued in June 2014. The Tailoring Rule remains applicable for those facilities considered major sources of six other “criteria” pollutants. In August 2016, the EPA proposed changes needed to bring EPA’s air permitting regulations in line with the Supreme Court’s decision on greenhouse gas permitting. The proposed rule was published in the Federal Register in October 2016 and the public comment period closed in December 2016.

Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including NGLs fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which includes certain of our facilities, beginning in 2012 for emissions occurring in 2011. Amendments to the GHG reporting rule, revising certain calculation methods and clarifying certain terms, became final in early 2015. Effective January 1, 2016, the EPA extended the reporting rule to include emissions from completions and workovers of oil wells using hydraulic fracturing, as well as emissions from gathering and boosting systems. As a result of this continued regulatory focus, future GHG regulations of the oil and natural gas industry remain a possibility.

On November 15, 2016, the BLM finalized a waste prevention rule for oil and gas facilities on onshore federal and Indian leases to prohibit venting, limit flaring, require leak detection, and allow adjustment of royalty rates for new leases. State and industry groups have challenged the rule in federal court, asserting that the BLM lacks the authority to prescribe air quality regulations. The rule went into effect in January 2017 and could require installation of tank vapor controls at over 70 existing well sites in the Altamont area at an estimated cost of approximately $5 million. However, on March 28, 2017, the President signed an executive order directing the BLM to review the above rule and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 8, 2017, the BLM published a final rule to suspend or delay certain requirements of its

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2016 waste prevention rule until January 17, 2019. However, on February 22, 2018, a federal district court in California issued a preliminary injunction against BLM's suspension of the 2016 waste prevention rule. Also, on February 22, 2018, the BLM published proposed amendments to the final rule that would eliminate certain air quality provisions, including those that would require us to install tank vapor controls. At this time, it is uncertain to what extent the BLM's waste prevention rule will apply.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of such allowances is expected to escalate significantly. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce GHG emissions.

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The text of the resulting Paris Agreement calls for nations to undertake “ambitious efforts” to “hold the increase in global average temperatures to well below 2 ºC above preindustrial levels and pursue efforts to limit the temperature increase to 1.5 ºC above pre-industrial levels;” reach global peaking of GHG emissions as soon as possible; and take action to conserve and enhance sinks and reservoirs of GHGs, among other requirements. The Paris Agreement went into effect in November 2016. However, in June 2017, the President announced that the United States would withdraw from the Paris Agreement, and began negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Presidential administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Regulation of GHG emissions could result in reduced demand for our products, as oil and natural gas consumers seek to reduce their own GHG emissions. As our operations also emit GHGs directly, current and future laws or regulations limiting such emissions could increase our own costs. Any regulation of GHG emissions, including through a cap-and-trade system, technology mandate, emissions tax, reporting requirement or other program, could have a material adverse effect on our business, results of operations and financial condition.

Further, there have been various legislative and regulatory proposals at the federal and state levels to provide incentives and subsidies to (i) shift more power generation to renewable energy sources and (ii) support technological advances to drive less energy consumption. These incentives and subsidies could have a negative impact on oil, natural gas and NGLs consumption. In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital.

Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages, or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

In addition, to the extent climate change results in more severe weather and significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic effects, our own, our counterparties' or our customers' operations may be disrupted, which could result in a decrease in our available products or reduce our customers' demand for our products.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and health and safety laws and regulations applicable to our business.

There is inherent risk in our operations of incurring significant environmental costs and liabilities due to our generation and handling of petroleum hydrocarbons and wastes, because of our air emissions and wastewater discharges, and as a result of historical industry operations and waste disposal practices. Some of our owned and leased properties have been used for oil and natural gas exploration and production activities for a number of years, often by third parties not under our control. During that time, we and/or other owners and operators of these facilities may have generated or disposed of wastes that polluted the soil, surface water or groundwater at our facilities and adjacent properties. For our non-operated properties, we are dependent on the operator for operational and regulatory compliance. We could be subject to claims for personal injury and/or natural resource and property damage (including site clean-up and restoration costs) related to the environmental, health or safety impacts of our oil and natural gas production activities, and we have been from time to time, and currently are, named as a defendant in litigation related to such matters. Under certain laws, we also could be subject to joint and several and/or strict liability for the removal or remediation of contamination regardless of whether such contamination was the result of our activities, even if the operations were in compliance with all applicable laws at the time the contamination occurred and even if we no longer own and/or operate on the properties. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. We have been and continue to be responsible for remediating contamination, including at some of our current and former facilities or areas where we produce hydrocarbons. While to date none of these obligations or claims have involved costs that have materially adversely affected our business, we cannot predict with certainty whether future costs of newly discovered or new contamination might result in a materially adverse impact on our business or operations.

There have been various regulations proposed and implemented that could materially impact the costs of exploration and production operations and cause substantial delays in the receipt of regulatory approvals from both an environmental and safety perspective. It is possible that more stringent regulations might be enacted or delays in receiving permits may occur in other areas, such as our onshore regions of the United States (including drilling operations on other federal or state lands).

Our operations could result in an equipment malfunction or oil spill that could expose us to significant liability.

Despite the existence of various procedures and plans, there is a risk that we could experience well control problems in our operations. As a result, we could be exposed to regulatory fines and penalties, as well as landowner lawsuits resulting from any spills or leaks that might occur. While we maintain insurance against some of these risks in amounts that we believe are reasonable, our insurance coverages have material deductibles, self-insurance levels and limits on our maximum recovery and do not cover all risks. For example, from time to time we may not carry, or may be unable to obtain on terms that we find acceptable and/or reasonable, insurance coverage for certain exposures including, but not limited to, certain environmental exposures (including potential environmental fines and penalties), business interruption and named windstorm/hurricane exposures and, in limited circumstances, certain political risk exposures. The premiums and deductibles we pay for certain insurance policies are also subject to the risk of substantial increases over time that could negatively impact our financial results. In addition, we may not be able to renew existing insurance policies or procure desirable insurance on commercially reasonable terms. There is also a risk that our insurers may default on their insurance coverage obligations or that amounts for which we are insured, or that the proceeds of such insurance, will not compensate us fully for our losses. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

Although we might also have remedies against our contractors or vendors or our joint working interest owners with regard to any losses associated with unintended spills or leaks, the ability to recover from such parties will depend on the indemnity provisions in our contracts as well as the facts and circumstances associated with the causes of such spills or leaks. As a result, our ability to recover associated costs from insurance coverages or other third parties is uncertain.

Legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

We use hydraulic fracturing extensively in our operations. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The Safe Drinking Water Act (SDWA) regulates the underground injection of substances through the Underground Injection Control (UIC) program. While hydraulic fracturing generally is exempt from regulation under the UIC program, Congress has in recent legislative sessions considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process. In addition, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program as "Class II" UIC wells. Also, in June 2016, EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a

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study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

In August 2012, the EPA published final regulations under the Clean Air Act (CAA) that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA promulgated New Source Performance Standards establishing emission limits for sulfur dioxide (SO2) and volatile organic compounds (VOCs). The final rules require a 95% reduction in VOCs emitted by mandating the use of reduced emission completions or "green completions" on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. Until this date, emissions from fractured and refractured gas wells were to be reduced through reduced emission completions or combustion devices. The rules also establish new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. In response to numerous requests for reconsideration of these rules from both industry and the environmental community and court challenges to the final rules, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, in May 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, the President directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. In June 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

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

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. In December 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, in February 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These studies, when final and depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Several states and local jurisdictions in which we operate have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, Texas enacted a law requiring oil and natural gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission adopted rules and regulations applicable to all wells for which the Texas Railroad Commission issues an initial drilling permit on or after February 1, 2012. The regulations require that well operators disclose the list of chemical ingredients subject to the requirements of the Occupational Safety and Health Administration (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Furthermore, in May 2013, the Texas Railroad Commission issued an updated “well integrity rule,” addressing requirements for drilling, casing and cementing wells, which took effect in January 2014. In addition, Utah’s Division of Oil, Gas and Mining passed a rule in October 2012 requiring all oil and gas operators to disclose the amount and type of chemicals used in hydraulic fracturing operations using the national registry FracFocus.org.

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A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. If new laws or regulations that significantly restrict hydraulic fracturing, such as amendments to the SDWA, are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. Until such regulations are finalized and implemented, it is not possible to estimate their impact on our business. At this time, no adopted regulations have imposed a material impact on our hydraulic fracturing operations.
Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.
Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. For example, in October 2014, the Texas Railroad Commission adopted disposal well rule amendments designed to among other things, require applicants for new disposal wells that will receive non-hazardous produced water or other oil and gas waste to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well. The Commission has used this authority to deny permits for waste disposal wells.

Tax laws and regulations may change over time, including the elimination of federal income tax deductions currently available with respect to oil and gas exploration and development.
Tax laws and regulations are highly complex and subject to interpretation, and the tax laws and regulations to which we are subject may change over time. Our tax filings are based upon our interpretation of the tax laws in effect in various jurisdictions at the time that the filings were made. If these laws or regulations change, or if the taxing authorities do not agree with our interpretation of the effects of such laws and regulations, it could have a material adverse effect on our business and financial condition.
On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the Act) that significantly reforms the Internal Revenue Code of 1986, as amended (the Code). Among other changes, the Act (i) permanently reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) eliminates the deduction for certain domestic production

activities, (iv) imposes new limitations on the utilization of net operating losses generated after 2017, and (v) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. Given the complexity and breadth of the Act, the ultimate impact of the Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued, and any such changes in our interpretations or assumptions could have an adverse effect on our business, results of operations, and financial condition.

In past years, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including:

- the repeal of the percentage depletion allowance for oil and gas properties;
- the elimination of current expensing of intangible drilling and development costs; and
- an extension of the amortization period for certain geological and geophysical expenditures.

While these specific changes are not included in the Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could have a material adverse effect on our business, results of operations and financial condition.

We have certain contingent liabilities that could exceed our estimates.

We have certain contingent liabilities associated with litigation, regulatory, environmental and tax matters described in Part II, Item 8, "Financial Statements and Supplementary Data", Note 9 to our consolidated financial statements and elsewhere in this Annual Report on Form 10-K. In addition, the positions taken in our federal, state, local and previously in non-U.S. tax returns require significant judgments, use of estimates and interpretation of complex tax laws. Although we believe that we have established appropriate reserves for our litigation, regulatory, environmental and tax matters, we could be required to accrue additional amounts in the future and/or incur more actual cash expenditures than accrued for and these amounts could be material.

Retained liabilities associated with businesses or assets that we have sold could exceed our estimates and we could experience difficulties in managing these liabilities.

We have sold various assets and either retained certain liabilities or indemnified certain purchasers against future liabilities relating to businesses and assets sold, including breaches of warranties, environmental expenditures, asset retirements and other representations that we have provided. We may also be subject to retained liabilities with respect to certain divested assets by operation of law. For example, the recent and sustained decline in commodity prices has created an environment where there is an increased risk that owners and/or operators of assets purchased from us may no longer be able to satisfy plugging or abandonment obligations that attach to such assets. In that event, due to operation of law, we may be required to assume these plugging or abandonment obligations on assets no longer owned and operated by us. Although we believe that we have established appropriate reserves for any such liabilities, we could be required to accrue additional amounts in the future and these amounts could be material.

Our debt agreements contain restrictions that limit our flexibility in operating our business.

Our existing debt agreements contain, and any other existing or future indebtedness of ours would likely contain, a number of covenants that impose operating and financial restrictions on us, including restrictions on our and our subsidiaries ability to, among other things:

- incur additional debt, guarantee indebtedness or issue certain preferred shares;
- pay dividends on or make distributions in respect of, or repurchase or redeem, our capital stock or make other restricted payments;
- prepay, redeem or repurchase certain debt;
- make loans or certain investments;
- sell certain assets;
- create liens on certain assets;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets;
- enter into certain transactions with our affiliates;
- alter the businesses we conduct;
- enter into agreements restricting our subsidiaries’ ability to pay dividends; and
- designate our subsidiaries as unrestricted subsidiaries.

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In addition, the RBL Facility requires us to comply with certain financial covenants. See Part II, Item 8, "Financial Statements and Supplementary Data", Note 8 for additional discussion of the RBL covenants.

As a result of these covenants, we may be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

A failure to comply with the covenants under the RBL Facility or any of our other indebtedness could result in an event of default, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. In the event of any such default, the lenders thereunder:

- will not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable and terminate all commitments to extend further credit; or
- could require us to apply all of our available cash to repay these borrowings.

Such actions by the lenders could cause cross defaults under our other indebtedness. If we were unable to repay those amounts, the lenders or holders under the RBL Facility and our other secured indebtedness could proceed against the collateral granted to them to secure that indebtedness. We pledge a significant portion of our assets as collateral under the RBL Facility, our senior secured term loans and our secured notes.

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ITEM 1B. UNRESOLVED STAFF COMMENTS
None.
ITEM 2. PROPERTIES
A description of our properties is included in Part I, Item 1, "Business", and is incorporated herein by reference.
We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.
ITEM 3. LEGAL PROCEEDINGS
A description of our material legal proceedings is included in Part II, Item 8, "Financial Statements and Supplementary Data", Note 9, and is incorporated herein by reference.
ITEM 4. MINE SAFETY DISCLOSURES
Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Our common stock started trading on the New York Stock Exchange under the symbol EPE on January 17, 2014. As of February 16, 2018, we had 43 stockholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

Quarterly Stock Prices. The following table reflects the quarterly high and low sales prices for the last two fiscal years for our common stock based on the daily composite listing of stock transactions for the New York Stock Exchange:

	2017		2016	
	High	Low	High	Low
Fourth Quarter	$3.46	$1.54	$7.49	$3.29
Third Quarter	3.90	2.70	5.43	3.36
Second Quarter	5.27	3.32	6.88	3.70
First Quarter	6.94	4.01	7.44	1.60

Stock Performance Graph

The performance graph and the information contained in this section is not "soliciting material", is being "furnished" not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing.

The graph below compares the change in the cumulative total shareholder return assuming the investment of $100 on January 17, 2014 (our first trading day) in each of EP Energy's Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration and Production Index. The historical stock performance shown on the graph below is not indicative of future price performance.

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	January 17, 2014	December 31, 2014	December 31, 2015	December 31, 2016	December 31, 2017
EP Energy Corporation	$100.00	$ 57.74	$ 24.23	$ 36.23	$ 13.05
S&P 500 Index	100.00	111.98	111.16	121.76	145.41
Dow Jones U.S. Exploration and Production Index	100.00	90.49	67.72	82.91	82.70

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ITEM 6. SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

Set forth below is our selected historical consolidated financial data for the periods and as of the dates indicated. We have derived the selected historical consolidated balance sheet data as of December 31, 2017 and December 31, 2016 and the statements of income data and statements of cash flow data for the years ended December 31, 2017, December 31, 2016 and December 31, 2015, from the audited consolidated financial statements of EP Energy Corporation included in this Annual Report on Form 10-K. We have derived the selected historical consolidated balance sheet data as of December 31, 2015, 2014 and 2013, and the statements of income data and statements of cash flow data for the year ended December 31, 2014 and 2013 from the consolidated financial statements of EP Energy Corporation, which are not included in this Annual Report on Form 10-K. Financial statements for the years ended and as of December 31, 2014 and 2013 present certain domestic natural gas assets and our Brazil operations as discontinued operations prior to their sale.

The following selected historical financial data should be read in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8, "Financial Statements and Supplementary Data" included in this Annual Report on Form 10-K.

	Year ended December 31,				
	2017	2016	2015	2014	2013
	(in millions, except per common share amounts)				
Results of Operations					
Operating revenues	$1,066	$767	$ 1,908	$3,084	$1,576
Impairment charges	2	2	4,299	2	2
Operating income (loss)	139	(98)	(3,955)	1,493	383
(Loss) gain on extinguishment of debt	(16)	384	(41)	(17)	(9)
Interest expense	(326)	(312)	(330)	(318)	(354)
(Loss) income from continuing operations	(194)	(27)	(3,748)	727	(56)
Basic and diluted net income (loss) per common share					
(Loss) income from continuing operations	$(0.79)	$(0.11)	$ (15.37)	$3.00	$(0.27)
Cash Flow					
Net cash provided by (used in):					
Operating activities	$375	$784	$ 1,327	$1,186	$960
Investing activities	(577)	(144)	(1,543)	(2,044)	(474)
Financing activities	227	(646)	220	829	(503)

	As of December 31,				
	2017	2016	2015	2014	2013
	(in millions)				
Financial Position					
Total assets	$4,900	$4,761	$ 5,833	$10,154	$8,257
Long-term debt, net of debt issue costs	4,022	3,789	4,812	4,533	4,340
Stockholders'/ Member's equity	392	606	619	4,348	2,937

Factors Affecting Trends. In 2014, we completed an initial public offering of approximately $669 million of common stock. Our operating revenues include realized and unrealized gains or losses on financial derivatives. For the years ended December 31, 2017, 2016, 2015, 2014 and 2013, we recorded realized and unrealized gains of $41 million, losses of $73 million, gains of $667 million, gains of $985 million and losses of $52 million on financial derivatives, respectively. For the year ended December 31, 2015, we recorded non-cash impairment charges of approximately $4.3 billion on our proved and unproved properties. Additional items affecting trends were a gain on sale of assets of $78 million and a gain on extinguishment of debt of $384 million recorded during the year ended December 31, 2016.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Our Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with the financial statements and the accompanying notes presented in Item 8 of this Annual Report on Form 10-K. This discussion contains forward-looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in "Risk Factors". Actual results may differ materially from those contained in any forward-looking statements. See "Cautionary Statement Regarding Forward-Looking Statements" in the front of this report. Unless otherwise indicated or the context otherwise requires, references in this MD&A section to "we", "our", "us" and "the Company" refer to EP Energy Corporation and each of its consolidated subsidiaries.

Our Business

Overview. We are an independent exploration and production company engaged in the acquisition and development of unconventional onshore oil and natural gas properties in the United States. We operate through a diverse base of producing assets and are focused on providing returns to our shareholders through the development of our drilling inventory located in three areas: the Permian basin in West Texas, the Eagle Ford Shale in South Texas, and the Altamont Field in the Uinta basin in Northeastern Utah, which are further described in Part I, Item I, "Business".

Our strategy is to invest in opportunities that provide the highest return across our asset base, continually seek out operating and capital efficiencies, effectively manage costs, and identify accretive acquisition opportunities and divestitures, all with the objective of enhancing our portfolio, growing asset value, improving cash flow, increasing financial flexibility and providing an attractive return to our shareholders. We evaluate opportunities in our portfolio that are aligned with this strategy and our core competencies and that offer a competitive advantage. In addition to opportunities in our current portfolio, strategic acquisitions of leasehold acreage or acquisitions of producing assets allow us to leverage existing expertise in our areas, balance our exposure to regions, basins and commodities, help us to achieve or enhance risk-adjusted returns competitive with those available in our existing programs and increase our reserves. We also continuously evaluate our asset portfolio and will sell oil and natural gas properties if they no longer meet our long-term objectives.

During 2017, we acquired proved and unproved properties located in the Permian basin for approximately $29 million and entered into an agreement to acquire certain producing properties and undeveloped acreage in Eagle Ford primarily in La Salle County for approximately $245 million, subject to customary closing adjustments. Our Eagle Ford acquisition closed on January 31, 2018 and represents a 26 percent expansion of our current Eagle Ford acreage position or approximately 24,500 net acres. In 2017, we also entered into an agreement to divest certain assets in the Altamont area for approximately $180 million of cash proceeds, subject to customary closing adjustments. This divestiture represents approximately 13 percent of our current Altamont acreage position or approximately 23,330 net acres. We closed this transaction in February 2018.

From time to time, we will enter into joint ventures to enhance the development of wells, hold acreage and/or improve near-term economics in our programs. In January and May 2017, we entered into drilling joint ventures in our Permian and Altamont programs. In the Permian, our partner may participate in the development of up to 150 wells in two separate 75 well tranches primarily in Reagan and Crockett counties. Our joint venture investor may fund approximately $450 million over the entire program, or approximately 60 percent of the estimated drilling, completion and equipping costs of the wells in exchange for a 50 percent working interest in the joint venture wells. The first wells under the joint venture began producing in January 2017 and as of December 31, 2017, we have drilled and completed 58 wells in the first tranche. For a further discussion on this joint venture, see Part II, Item 8, "Financial Statements and Supplementary Data", Note 11. In Altamont, our partner is participating in the development of 60 wells and will provide a capital carry in exchange for a 50 percent working interest in the joint venture wells. The first wells under the joint venture began producing in July 2017 and as of December 31, 2017, we have drilled and completed 16 wells. We are the operator of the assets in both joint ventures.

Factors Influencing Our Profitability. Our profitability is dependent on the prices we receive for our oil and natural gas, the costs to explore, develop, and produce our oil and natural gas, and the volumes we are able to produce, among other factors. Our long-term profitability will be influenced primarily by:

- growing our proved reserve base and production volumes through the successful execution of our drilling programs or through acquisitions;
- finding and producing oil and natural gas at reasonable costs;
- managing operating costs; and
- managing commodity price risks on our oil and natural gas production.

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In addition to these factors, our future profitability and performance will be affected by volatility in the financial and commodity markets, changes in the cost of drilling and oilfield services, operating and capital costs, and our debt level and related interest costs. Future commodity price changes may affect our future capital spending levels, production rates and/or related operating revenues (net of any associated royalties), levels of proved reserves and development plans, all of which impact performance. Additionally, we may be impacted by weather events, regulatory issues or other third party actions outside of our control.

Forward commodity prices play a significant role in determining the recoverability of proved or unproved property costs on our balance sheet. While prices have generally improved over the past two years, future price declines along with changes to our future capital spending levels, production rates, levels of proved reserves and development plans may result in an impairment of the carrying value of our proved and/or unproved properties in the future, and such charges could be significant. For a further discussion of our proved and unproved property costs, see Part II, Item 8, "Financial Statements and Supplementary Data", Note 3 and Critical Accounting Estimates for key assumptions and judgments used in these estimations.

Derivative Instruments. Our realized prices from the sale of our oil, natural gas and NGLs are affected by (i) commodity price movements, including locational or basis price differences that exist between the commodity index price (e.g., WTI) and the actual price at which we sell our commodity and (ii) other contractual pricing adjustments contained in our underlying sales contracts. In order to stabilize cash flows and protect the economic assumptions associated with our capital investment programs, we enter into financial derivative contracts to reduce the financial impact of downward commodity price movements and unfavorable movements in locational prices. Adjustments to our strategy and the decision to enter into new contracts or positions to alter existing contracts or positions are made based on the goals of the overall company. Because we apply mark-to-market accounting on our derivative contracts, our reported results of operations and financial position can be impacted significantly by commodity price movements from period to period.

During 2017, we (i) settled commodity index hedges on approximately 65% of our oil production, 57% of our total liquids production and 69% of our natural gas production at average floor prices of $60.85 per barrel of oil, $0.44 per gallon of NGLs and $3.28 per MMBtu of natural gas, respectively. To the extent our oil, natural gas and NGLs production is unhedged, either from a commodity index or locational price perspective, our operating revenues will be impacted from period to period. The following table and discussion reflects the contracted volumes and the prices we will receive under derivative contracts we held as of December 31, 2017.

	2018		2019	
	Volumes[1]	Average Price[1]	Volumes[1]	Average Price[1]
Oil				
Fixed Price Swaps				
WTI	4,745	$ 56.22	—	$ —
Three Way Collars				
Ceiling - WTI	8,859	$ 68.15	—	$ —
Floors - WTI	8,859	$ 60.00	—	$ —
Sub-Floor - WTI	8,859	$ 50.00	—	$ —
Basis Swaps				
LLS vs. WTI[2]	5,110	$ 2.84	—	$ —
Midland vs. Cushing[3]	4,380	$ (1.02)	—	$ —
NYMEX Roll[4]	3,650	$ 0.09	—	$ —
Natural Gas				
Fixed Price Swaps	26	$ 3.04	7	$ 2.97
Basis Swaps				
WAHA vs. Henry Hub[5]	15	$ (0.46)	7	$ (0.39)
NGLs				
Fixed Price Swaps - Ethane	61	$ 0.30	—	$ —

Fixed Price Swaps - Propane	31	$0.75	—$—

(1) Volumes presented are MBbls for oil, TBtu for natural gas and MMGal for NGLs. Prices presented are per Bbl of oil, MMBtu of natural gas and Gal for NGLs.
(2) EP Energy receives WTI plus the basis spread listed and pays LLS.
(3) EP Energy receives Cushing plus the basis spread listed and pays Midland.
(4) These positions hedge the timing risk associated with our physical sales. We generally sell oil for the delivery month at a sales price based on the average NYMEX WTI
price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month
during the period when the delivery month is prompt (the "trade month roll").
(5) EP Energy receives Henry Hub plus the basis spread listed and pays WAHA.

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For the period from January 1, 2018 through February 27, 2018, we entered into the following additional derivative contracts.

	2018		2019	
	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)
Oil				
Fixed Price Swaps				
WTI	334	$60.00	730	$55.88
Collars				
Ceiling - WTI	1,002	$64.98	—	$—
Floors - WTI	1,002	$55.00	—	$—
Three Way Collars				
Ceiling - WTI	—	$—	1,095	$65.05
Floors - WTI	—	$—	1,095	$55.00
Sub-Floor - WTI	—	$—	1,095	$45.00
Basis Swaps				
Midland vs. Cushing(2)	306	$(1.06)	—	$—

(1) Volumes presented are MBbls for oil. Prices presented are per Bbl of oil.
(2) EP Energy receives Cushing plus the basis spread listed and pays Midland.

For our three-way collar contracts in the tables above, the sub-floor prices represent the price below which we receive WTI plus a weighted average spread of $10.00 in 2018 and 2019 on the indicated volumes. If WTI is above our sub-floor prices, we receive the noted floor price until WTI exceeds that floor price. Above the floor price, we receive WTI until prices exceed the noted ceiling price in our three way collars, at which time we receive the fixed ceiling price. As of December 31, 2017, the average forward price of oil was $59.31 per barrel of oil for 2018 and $55.87 per barrel of oil for 2019.

Summary of Liquidity and Capital Resources. As of December 31, 2017, we had available liquidity of approximately $813 million, reflecting $786 million of available liquidity on our Reserve-Based Loan facility (RBL Facility) borrowing base and $27 million of available cash. In 2017 and into the first part of 2018, we took a number of steps to improve our liquidity, expand our financial flexibility and manage our leverage. During 2017, these actions included (i) issuing $1 billion of 8.00% 2025 senior secured notes using the net proceeds to repay/repurchase $830 million of 2020/2021 senior notes and senior secured term loans and repay $111 million under our RBL Facility and (ii) repurchasing for cash a total of $157 million in aggregate principal amount of senior unsecured notes due 2020 and 2023 for approximately $118 million.

In addition, in April 2017, we amended our credit agreement, extending the first lien debt to EBITDAX covenant through March 31, 2019, reducing it such that the ratio of first lien debt to EBITDAX may not exceed 3.0 to 1.0. In 2018, we exchanged approximately $1,147 million of the outstanding amounts of our senior unsecured notes maturing in 2020, 2022 and 2023 for new 9.375% senior secured notes maturing in 2024. As a result of this transaction the RBL Facility borrowing base was reduced from $1.4 billion to $1.36 billion. Our RBL Facility is our primary source of liquidity beyond our operating cash flow and matures in May of 2019. We are currently working to renew and extend both the maturity of the facility as well as the required covenants thereunder.

During 2017, we also entered into transactions to enhance capital efficiency and pursue acquisitions while doing so in a cash or leverage enhancing manner, including (i) entering into two drilling joint ventures in the Altamont and Permian basin and (ii) entering into our largest acquisition agreement to date in December 2017 in the Eagle Ford for approximately $245 million (which closed on January 31, 2018), while at the same time (iii) entering into an agreement to divest certain assets in Altamont for approximately $180 million (which closed on February 9, 2018). For a further discussion of our liquidity and capital resources, including factors that could impact our liquidity, see Liquidity and Capital Resources.

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Outlook. In our capital program in 2018, we expect to spend approximately $600 million to $650 million in capital (not including acquisition capital), with approximately 50% allocated to the Eagle Ford Shale, approximately 30% allocated to the Permian basin and approximately 20% allocated to Altamont. We anticipate our average daily production volumes for the year to be approximately 81 MBoe/d to 87 MBoe/d, including average daily oil production volumes of approximately 46 MBbls/d to 50 MBbls/d.

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Production Volumes and Drilling Summary

Production Volumes. Below is an analysis of our production volumes for the years ended December 31:

	2017	2016	2015
United States (MBoe/d)			
Permian	28.7	21.4	19.9
Eagle Ford Shale	35.7	43.5	58.2
Altamont	17.9	16.5	17.1
Other(1)	—	6.2	14.5
Total	82.3	87.6	109.7
Oil (MBbls/d)	46.1	46.6	60.5
Natural Gas (MMcf/d)(1)	127	158	207
NGLs (MBbls/d)	15.0	14.7	14.7

(1) Primarily consists of Haynesville Shale, which was sold in May 2016. For the years ended December 31, 2016 and 2015, natural gas volumes included 37 MMcf/d and 87 MMcf/d, respectively, from the Haynesville Shale.

- Permian —Our Permian basin equivalent volumes increased 7.3 MBoe/d (approximately 34%) and oil production increased by 2.8 MBbls/d (approximately 33%) for the year ended December 31, 2017 compared to 2016. Our production increases reflect incremental capital allocated to this program in 2016 and 2017. During 2017, we completed 71 additional operated wells (many of which were completed as part of our joint venture), for a total of 332 net operated wells as of December 31, 2017.
- Eagle Ford Shale—Our Eagle Ford Shale equivalent volumes decreased by 7.8 MBoe/d (approximately 18%) and oil production decreased by 4.1 MBbls/d (approximately 15%) for the year ended December 31, 2017 compared to 2016. Our production declines reflect natural declines and the slowed pace of development in our drilling program due to reduced capital spending since 2016. During 2017, we completed 53 additional operated wells in the Eagle Ford, for a total of 628 net operated wells as of December 31, 2017.
- Altamont—Our Altamont equivalent volumes increased 1.4 MBoe/d (approximately 8%) and oil production increased by 0.8 MBbls/d (approximately 7%) for the year ended December 31, 2017 compared to 2016. During 2017, we completed 25 additional operated oil wells, for a total of 377 net operated wells as of December 31, 2017. We also recompleted 59 wells across our Altamont acreage.

Future volumes across all our assets will be impacted by the level of natural declines, and the level and timing of capital spending in each respective area.

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Results of Operations

The information below reflects financial results for EP Energy Corporation for the years ended December 31, 2017, 2016 and 2015.

	Year ended December 31,		
	2017	2016	2015
	(in millions)		
Operating revenues:			
Oil	$812	$653	$981
Natural gas	110	122	200
NGLs	103	65	60
Total physical sales	1,025	840	1,241
Financial derivatives	41	(73)	667
Total operating revenues	1,066	767	1,908
Operating expenses:			
Oil and natural gas purchases	2	10	31
Transportation costs	115	109	116
Lease operating expense	163	159	186
General and administrative	81	146	148
Depreciation, depletion and amortization	487	462	983
Gain on sale of assets	—	(78)	—
Impairment charges	2	2	4,299
Exploration and other expense	12	5	20
Taxes, other than income taxes	65	50	80
Total operating expenses	927	865	5,863
Operating income (loss)	139	(98)	(3,955)
(Loss) gain on extinguishment of debt	(16)	384	(41)
Interest expense	(326)	(312)	(330)
Loss before income taxes	(203)	(26)	(4,326)
Income tax benefit (expense)	9	(1)	578
Net loss	$(194)	$(27)	$(3,748)

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the years ended December 31, 2017, 2016 and 2015. We present (i) average realized prices based on physical sales of oil, natural gas and NGLs as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements and premiums which reflect cash received or paid during the respective period.

	Year ended December 31,		
	2017	2016	2015
		(in millions)	
Operating revenues:			
Oil	$812	$ 653	$981
Natural gas	110	122	200
NGLs	103	65	60
Total physical sales	1,025	840	1,241
Financial derivatives	41	(73)	667
Total operating revenues	$1,066	$ 767	$1,908
Volumes:			
Oil (MBbls)	16,833	17,061	22,078
Natural gas (MMcf)(1)	46,356	57,799	75,533
NGLs (MBbls)	5,465	5,383	5,366
Equivalent volumes (MBoe)(1)	30,024	32,077	40,033
Total MBoe/d(1)	82.3	87.6	109.7
Prices per unit(2):			
Oil			
Average realized price on physical sales ($/Bbl)(3)	$48.23	$ 38.24	$44.28
Average realized price, including financial derivatives ($/Bbl)(3)(4)	$53.50	$ 74.88	$82.18
Natural gas			
Average realized price on physical sales ($/Mcf)(3)	$2.32	$ 1.95	$2.27
Average realized price, including financial derivatives ($/Mcf)(3)(4)	$2.47	$ 2.19	$3.59
NGLs			
Average realized price on physical sales ($/Bbl)	$18.87	$ 12.02	$11.22
Average realized price, including financial derivatives ($/Bbl)(4)	$18.46	$ 12.19	$12.36

(1) For the years ended December 31, 2016 and 2015, Haynesville Shale production volumes were 13,556 MMcf of natural gas and 2,259 MBoe (6.2 MBoe/d) of equivalent volumes and 31,521 MMcf of natural gas and 5,253 MBoe (14.4 MBoe/d) of equivalent volumes, respectively.

(2) For the year ended December 31, 2017, there were no oil purchases associated with managing our physical oil sales. Oil prices for the years ended December 31, 2016 and 2015 reflect operating revenues for oil reduced by $1 million and $3 million, respectively, for oil purchases associated with managing our physical sales. Natural gas prices for the years ended December 31, 2017, 2016 and 2015 reflect operating revenues for natural gas reduced by $2 million, $9 million and $28 million, respectively, for natural gas purchases associated with managing our physical sales.

(3) Changes in realized oil and natural gas prices reflect the effects of unhedged locational or basis differentials, unhedged volumes and contractual deductions between the commodity price index and the actual price at which we sold our oil and natural gas.

(4) The years ended December 31, 2017, 2016 and 2015 include approximately $89 million, $625 million and $837 million, respectively, of cash received for the settlement of crude oil derivative contracts. The years ended December 31, 2017, 2016 and 2015 include approximately $7 million, $13 million and $99 million, respectively, of cash received for the settlement of natural gas financial derivatives. The years ended December 31, 2017, 2016

and 2015 include approximately $3 million of cash paid, $1 million of cash received and $6 million of cash received, respectively, for the settlement of NGLs derivative contracts. No cash premiums were received or paid for the years ended December 31, 2017, 2016 and 2015.

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Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the year ended December 31, 2017, physical sales increased by $185 million (22%), compared to the year ended December 31, 2016. For the year ended December 31, 2016, physical sales decreased by $401 million (32%) compared to the year ended December 31, 2015. The table below displays the price and volume variances on our physical sales when comparing the years ended December 31, 2017, 2016 and 2015.

	Oil	Natural gas	NGLs	Total
	(in millions)			
December 31, 2016 sales	$653	$ 122	$ 65	$840
Change due to prices	168	12	37	217
Change due to volumes	(9)	(24)	1	(32)
December 31, 2017 sales	$812	$ 110	$ 103	$1,025

	Oil	Natural gas	NGLs	Total
	(in millions)			
December 31, 2015 sales	$981	$ 200	$ 60	$1,241
Change due to prices	(105)	(31)	5	(131)
Change due to volumes	(223)	(47)	—	(270)
December 31, 2016 sales	$653	$ 122	$ 65	$840

Overall, physical sales in 2017 increased primarily due to higher commodity prices. Oil sales for the year ended December 31, 2017, compared to the year ended December 31, 2016, increased by $159 million (24%), due primarily to higher oil prices and higher oil production in the Permian and Altamont offset by lower oil production in Eagle Ford. In 2017, Permian oil production volumes increased by 33% (2.8 MBbls/d) and Altamont oil production increased by 7% (0.8 MBbls/d), while Eagle Ford oil production volumes decreased by 15% (4.1 MBbls/d) compared with the year ended December 31, 2016. For the year ended December 31, 2016, oil sales decreased by $328 million compared to the year ended December 31, 2015 due primarily to a decline in oil volumes in all of our oil programs reflecting the slowed pace of development and lower oil prices.

Natural gas sales decreased by $12 million (10%) for the year ended December 31, 2017 compared with the year ended December 31, 2016, due to lower volumes partially offset by higher natural gas prices. In May 2016, we sold our Haynesville Shale assets. Our Haynesville Shale assets produced a total of 37 MMcf/d of natural gas for the year ended December 31, 2016 prior to it being sold. Partially offsetting the decrease attributable to Haynesville was natural gas volume growth in the Permian and Altamont. Natural gas sales decreased for the year ended December 31, 2016 compared with the year ended December 31, 2015 primarily due to lower volumes as a result of the sale of Haynesville in 2016 and lower natural gas prices.

Our oil, natural gas and NGLs are sold at index prices (WTI, LLS, Henry Hub and Mt. Belvieu) or refiners' posted prices at various delivery points across our producing basins. Realized prices received (not considering the effects of hedges) are generally less than the stated index price as a result of fixed or variable contractual deductions, differentials from the index to the delivery point, adjustments for time, and/or discounts for quality or grade.

In the Eagle Ford, our oil is sold at prices tied to benchmark LLS crude oil. In the Permian, physical barrels are generally sold at the WTI Midland Index, which trades at a spread to WTI Cushing. In Altamont, market pricing of our oil is based upon NYMEX based agreements which reflect a locational difference at the wellhead. Across all regions, natural gas realized pricing is influenced by factors such as excess royalties paid on flared gas and the percentage of proceeds retained under processing contracts, in addition to the normal seasonal supply and demand influences and those factors discussed above. The table below displays the weighted average differentials and deducts on our oil and natural gas sales on an average NYMEX price.

	Year ended December 31,			
	2017		2016	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(2.92)	$ (0.79)	$(5.14)	$ (0.52)
NYMEX	$50.95	$ 3.11	$43.32	$ 2.46

Net back realization	% 94.3	% 74.6	% 88.1	% 78.9 %

The higher oil realization percentage in the year ended December 31, 2017 was primarily a result of improved LLS to WTI basis spread in Eagle Ford and improved physical sales contracts in all programs. The lower natural gas realization

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percentage in the year ended December 31, 2017 was primarily a result of the impact of the sale of our Haynesville assets and its associated lower basis differentials. Also impacting the lower natural gas realization percentage in 2017 was the impact on basis differentials in the Permian due to constrained natural gas takeaway capacity in the basin.
NGLs sales increased by $38 million (58%) for the year ended December 31, 2017 compared with 2016. Average realized prices for the year ended December 31, 2017 were higher compared to 2016, due to higher pricing on all liquid components. NGLs pricing is largely tied to crude oil prices. For the year ended December 31, 2016, NGLs sales increased by $5 million (8%) compared to 2015. While NGLs volumes remained flat in 2016 compared to 2015, average realized prices increased due to higher pricing on all liquids components.
Future growth in our overall oil, natural gas and NGLs sales (including the impact of financial derivatives) will largely be impacted by commodity pricing, our level of hedging, our ability to maintain or grow oil volumes and by the location of our production and the nature of our sales contracts. See "Our Business" and "Liquidity and Capital Resources" for further information on our derivative instruments.
Gains or losses on financial derivatives. We record gains or losses due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts. We realize such gains or losses when we settle the derivative position. During the year ended December 31, 2017, we recorded $41 million of derivative gains compared to derivative losses of $73 million during the year ended December 31, 2016. Realized and unrealized gains for the year ended December 31, 2015 were $667 million.
Operating Expenses
The tables below provide our operating expenses, volumes and operating expenses per unit for each of the periods presented:

	Year ended December 31,					
	2017		2016		2015	
	Total	Per Unit(1)	Total	Per Unit(1)	Total	Per Unit(1)
	(in millions, except per unit costs)					
Operating expenses						
Oil and natural gas purchases	$2	$ 0.07	$10	$ 0.32	$31	$ 0.79
Transportation costs	115	3.83	109	3.41	116	2.88
Lease operating expense	163	5.42	159	4.97	186	4.64
General and administrative(2)	81	2.69	146	4.54	148	3.71
Depreciation, depletion and amortization	487	16.22	462	14.40	983	24.54
Gain on sale of assets	—	—	(78)	(2.44)	—	—
Impairment charges	2	0.04	2	0.05	4,299	107.38
Exploration and other expense	12	0.40	5	0.16	20	0.50
Taxes, other than income taxes	65	2.19	50	1.58	80	2.00
Total operating expenses	$927	$ 30.86	$865	$ 26.99	$5,863	$ 146.44
Total equivalent volumes (MBoe)	30,024		32,077		40,033	

(1) Per unit costs are based on actual amounts rather than the rounded totals presented.

(2) For the year ended December 31, 2017, amount includes approximately $19 million or $0.64 per Boe of transition and severance costs related to workforce reductions, $(22) million or $(0.75) per Boe of non-cash compensation expense (net of forfeitures) and $5 million or $0.18 per Boe of fees paid to our Sponsors. For the year ended December 31, 2016, amount includes approximately $15 million or $0.47 per Boe of transition and severance costs related to workforce reductions and $19 million or $0.58 per Boe of non-cash compensation expense. For the year ended December 31, 2015, amount includes approximately $8 million or $0.20 per Boe of transition and severance costs related to workforce reductions and $13 million or $0.32 per Boe of non-cash compensation expense.

Oil and natural gas purchases. From time to time, we purchase and sell oil and natural gas to improve the prices we would otherwise receive for our oil and natural gas or to manage firm transportation agreements. Oil and natural gas purchases for the year ended December 31, 2017 decreased by $8 million compared to 2016 and for the year ended

December 31, 2016 decreased by $21 million compared to 2015, primarily due to fewer transactions following the sale of our Haynesville assets in May 2016.

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Transportation costs. Transportation costs for the year ended December 31, 2017 increased by $6 million in 2017 compared to 2016 due to an increase in gas transportation costs in the Permian as a result of production growth in that area and certain legacy transportation commitments that commenced in August 2016, partially offset by a decrease due to the sale of our Haynesville assets. Transportation costs decreases in 2016 compared to 2015 were primarily due to the sale of our Haynesville assets and a decrease in NGLs transportation costs partially offset by higher oil transportation costs in Eagle Ford.

Lease operating expense. Lease operating expense for the year ended December 31, 2017 increased by $4 million compared to 2016. The increase in 2017 compared to 2016 is due to higher maintenance, repair, disposal and chemical costs in the Permian and higher power and fuel costs in Altamont partially offset by a decrease due to lower disposal and chemical costs in Eagle Ford and the sale of Haynesville in 2016. On a per equivalent unit basis, lease operating expense increased 9% from $4.97 per Boe in 2016 to $5.42 per Boe in 2017 reflecting lower production volumes in 2017.

Total lease operating expense decreased by $27 million in 2016 compared to 2015 due to lower flowback, disposal and chemical costs in Eagle Ford as well as lower disposal costs, flowback and maintenance and repair costs in the Permian and a decrease due to the sale of Haynesville. On a per equivalent unit basis, however, lease operating expense increased 7% from $4.64 per Boe in 2015 to $4.97 per Boe in 2016 due to lower production volumes in 2016.

General and administrative expenses. General and administrative expenses for the year ended December 31, 2017 decreased by $65 million compared to 2016 related to lower payroll, benefits and administrative costs of approximately $33 million, lower rent expense of $7 million and lower costs of approximately $24 million related to a change in management. The costs related to the change in management included the impact of long-term incentive award forfeitures of approximately $33 million, offset by higher severance expense of $4 million and fees of $5 million incurred in connection with the release of members of the new leadership team from a portfolio company of funds managed by Apollo Global Management LLC and payment of certain legal expenses.

General and administrative expenses for the year ended December 31, 2016 decreased by $2 million compared to the year ended December 31, 2015. Lower costs during the year ended December 31, 2016 compared to 2015 included lower payroll, benefits and administrative costs of $15 million, offset by higher severance expense of $7 million and higher legal and professional fees of $6 million. The lower payroll, benefits and administrative costs in 2016 resulted primarily from a general and administrative headcount reduction of approximately 28% in response to the lower commodity price environment and the sale of Haynesville.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense for the year ended December 31, 2017 increased compared to 2016 due primarily to a reduction in reserves in Eagle Ford and higher volumes in the Permian and Altamont. Our Permian and Altamont areas have a higher depreciation, depletion and amortization expense cost per unit than Eagle Ford as a result of a non-cash impairment charge recorded in 2015 on our proved properties in Eagle Ford. For the year ended December 31, 2016, our depreciation, depletion and amortization expense was also impacted by an adjustment of approximately $29 million ($0.89 per Boe) to accrue for certain non-income tax items that would have been historically capitalized and amortized or impaired in prior periods.

Our depreciation, depletion and amortization costs decreased for the year ended December 31, 2016 compared to 2015 due primarily to the impact on depreciation, depletion and amortization of a non-cash impairment charge recorded in the fourth quarter of 2015 on our proved properties in Eagle Ford, the sale of our Haynesville Shale assets in May 2016 and an overall decrease in production volumes. Our average depreciation, depletion and amortization costs per unit for the year-to-date periods were:

	Year ended December 31,		
	2017	2016	2015
Depreciation, depletion and amortization ($/Boe)	$16.22	$14.40	$24.54

Our depreciation, depletion and amortization rate in the future will be impacted by the level and timing of capital spending, overall cost of capital and the level and type of reserves recorded on completed projects. For 2018, we currently anticipate our depreciation, depletion and amortization costs per unit to be between $16.50 and $17.50 per Boe.

Gain on sale of assets. For the year ended December 31, 2016, we recorded a $79 million gain related to the sale of our assets in the Haynesville and Bossier shales completed in May 2016.

Impairment charges. For the year ended December 31, 2015, we recorded non-cash impairment charges of approximately $4.0 billion on our proved properties in the Eagle Ford Shale and $288 million on our unproved properties in the Permian basin.

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Exploration and other expense. Exploration and other expense for the year ended December 31, 2017 increased by $7 million from 2016 and decreased by $15 million in 2016 from 2015. Included in exploration expense for the years ended December 31, 2017, 2016 and 2015 were $5 million, $2 million and $9 million, respectively, of amortization of unproved leasehold costs. The increase in 2017 reflects an increase in amortization of unproved leasehold costs, geological and geophysical costs in the Permian, and other expenses associated with certain contractual commitments. In 2015, we recorded approximately $2 million as other expense in conjunction with the early termination of contracts for drilling rigs, released in response to the lower price environment.

Taxes, other than income taxes. Taxes, other than income taxes for the year ended December 31, 2017 increased by $15 million from 2016 and decreased by $30 million from 2016 to 2015. The increase in 2017 compared to 2016 is due to an increase of severance taxes as a result of higher commodity prices. The decreases in 2016 compared to 2015 were due to the reduction in severance taxes as a result of lower commodity prices. Lower oil volumes in 2016 also contributed to the decrease from 2015.

Other Income Statement Items.

Loss (gain) on extinguishment of debt. During the year ended December 31, 2017, we retired our senior secured term loans due 2021 and a portion of our 9.375% senior notes due 2020, recording a loss on extinguishment of debt of approximately $53 million (including $30 million in non-cash expense related to eliminating associated unamortized debt issue costs and debt discounts). In 2017 and 2016, we also repurchased additional debt as follows:

	Year ended December 31,	
	2017	2016
	(in millions)	
Debt repurchased - face value(1)	157	812
Cash paid	118	407
Gain on extinguishment of debt(2)(3)	37	393

(1) In 2017, repurchases were associated with 2020 and 2023 senior unsecured notes. In 2016, repurchases were associated with certain senior unsecured notes and terms loans.

(2) Includes $2 million and $12 million for the years ended December 31, 2017 and 2016, respectively, of non-cash expense related to eliminating associated unamortized debt issue costs.

(3) For the years ended December 31, 2017 and 2016, we also recorded a loss on extinguishment of debt of approximately $1 million and $9 million primarily related to eliminating a portion of the unamortized debt issue costs on our RBL Facility due to the reduction of our borrowing base in October 2017 and May 2016, respectively.

For the year ended December 31, 2015, we recorded a $41 million loss ($12 million of which was non-cash) on the extinguishment of debt in conjunction with the early repayment and retirement of $750 million senior secured notes due 2019.

Interest expense. Interest expense for the year ended December 31, 2017 increased by $14 million compared to the same period in 2016 due primarily to higher average interest rates on outstanding borrowings in 2017 compared to 2016, partially offset by lower average borrowings under our RBL Facility. In late 2016 and early 2017, we issued $1.5 billion in senior secured notes due in 2024 and 2025. Proceeds from these offerings were used, in part, to repay or repurchase certain of our debt obligations and repay certain amounts outstanding under our RBL Facility.

Interest expense for the year ended December 31, 2016 compared to 2015 decreased due to the effects of our 2016 debt repurchases and debt exchanges/issuances, partially offset by higher interest expense related to our RBL Facility.

Income taxes. In December 2017, Congress passed into law the Tax Cuts and Jobs Act, which lowered the federal corporate tax rate from 35% to 21% effective January 1, 2018. Our effective tax rate for the year ended December 31, 2017 was 4.5%, which differed from the statutory rate of 35% primarily due to changes in our valuation allowance on our net deferred tax assets, non-deductible compensation expenses, and recording a current income tax benefit and related receivable for the recovery of previously paid alternative minimum taxes based on a change in our tax depreciation elections. For additional details on our income taxes, see Part II, Item 8, “Financial Statements and Supplementary Data”, Note 4.

The effective tax rate for the year ended December 31, 2016 was (1.9)%. Our effective tax rate differed from the statutory rate of 35% as a result of the effects of state income taxes (net of federal income tax effects), non-deductible compensation expense, and adjustments to the valuation allowance on our deferred tax assets, which offset deferred income tax benefits by $9 million for the year ended December 31, 2016. The effective tax rate in 2015 was 13.4%, lower than the statutory rate of 35% as a result of recording a valuation allowance of $975 million against our deferred tax assets.

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Supplemental Non-GAAP Measures

We use the non-GAAP measures "EBITDAX" and "Adjusted EBITDAX" as supplemental measures. We believe these supplemental measures provide meaningful information to our investors. We define EBITDAX as net income (loss) plus interest and debt expense, income taxes, depreciation, depletion and amortization and exploration expense. Adjusted EBITDAX is defined as EBITDAX, adjusted as applicable in the relevant period for the net change in the fair value of derivatives (mark-to-market effects of financial derivatives, net of cash settlements and cash premiums related to these derivatives), the non-cash portion of compensation expense (which represents non-cash compensation expense under our long-term incentive programs adjusted for cash payments made under these plans), transition, severance and other costs that affect comparability, fees paid to our Sponsors, gains and losses on sale of assets, gains and losses on extinguishment of debt and impairment charges.

We believe that the presentation of EBITDAX and Adjusted EBITDAX is important to provide management and investors with additional information (i) to evaluate our ability to service debt, adjusting for items required or permitted in calculating covenant compliance under our debt agreements, (ii) to provide an important supplemental indicator of the operational performance of our business without regard to financing methods and capital structure, (iii) for evaluating our performance relative to our peers, (iv) to measure our liquidity (before cash capital requirements and working capital needs) and (v) to provide supplemental information about certain material non-cash and/or other items that may not continue at the same level in the future. EBITDAX and Adjusted EBITDAX have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP or as an alternative to net income (loss), operating income (loss), operating cash flows or other measures of financial performance or liquidity presented in accordance with GAAP.

Below is a reconciliation of our consolidated net (loss) income to EBITDAX and Adjusted EBITDAX:

	Year ended December 31,		
	2017	2016	2015
	(in millions)		
Net loss	$(194)	$(27)	$(3,748)
Income tax (benefit) expense	(9)	1	(578)
Interest expense, net of capitalized interest	326	312	330
Depreciation, depletion and amortization	487	462	983
Exploration expense	9	5	18
EBITDAX	619	753	(2,995)
Mark-to-market on financial derivatives(1)	(41)	73	(667)
Cash settlements and cash premiums on financial derivatives(2)	93	639	942
Non-cash portion of compensation expense(3)	(22)	19	13
Transition, severance and other costs(4)	19	15	8
Fees paid to Sponsors	5	—	—
Gain on sale of assets(5)	—	(78)	—
Loss (gain) on extinguishment of debt(6)	16	(384)	41
Impairment charges	2	2	4,299
Adjusted EBITDAX	$691	$1,039	$1,641

(1) Represents the income statement impact of financial derivatives.

(2) Represents actual cash settlements related to financial derivatives. No cash premiums were received or paid for the years ended December 31, 2017, 2016 and 2015.

(3) For the years ended December 31, 2017, 2016 and 2015, cash payments were approximately $4 million, $3 million and $8 million, respectively.

(4) Reflects transition and severance costs related to workforce reductions.

(5) Represents the gain on the sale of our Haynesville Shale assets sold in May 2016.

(6) Represents the loss on extinguishment of debt recorded related to retiring our senior secured term loans and a portion or our senior notes offset by a gain on extinguishment of debt associated with repurchases of our senior

unsecured notes in 2017. Represents the gain on extinguishment of debt recorded related to repurchases of our senior unsecured notes and term loans in 2016. Represents the loss on extinguishment of debt recorded related to the repayment of our 2019 $750 million senior secured note in 2015.

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Liquidity and Capital Resources

Our primary sources of liquidity are cash generated by our operations and borrowings under our RBL Facility. Our primary uses of cash are capital expenditures, debt service, including interest, and working capital requirements. Our available liquidity was approximately $813 million as of December 31, 2017.

From a liquidity standpoint, our near-term strategic goal is to work towards cash flow neutrality by focusing on operating and capital efficiency, reducing cash costs and identifying accretive acquisition opportunities and divestitures while maintaining financial flexibility and managing our leverage. Our longer-term goal is to improve our cash flow to enhance our portfolio, grow our asset value and generate positive total returns for our shareholders. In 2017, we took a number of steps to improve our liquidity, expand our financial flexibility, and manage our leverage. During 2017, these actions included (i) issuing $1 billion of 8.00% 2025 senior secured notes using the net proceeds to repay/repurchase $830 million of 2020/2021 senior notes and secured term loans and repay $111 million under our RBL Facility and (ii) repurchasing for cash a total of $157 million in aggregate principal amount of senior unsecured notes due 2020 and 2023 for approximately $118 million. In 2018, we furthered these actions by exchanging $954 million, $54 million and $139 million of the outstanding amount of our senior unsecured notes maturing in May 2020, September 2022 and June 2023, respectively, for new 9.375% senior secured notes maturing in 2024 with an aggregate principal amount of approximately $1,092 million. Collectively, our actions over the past two years have had the impact of extending the maturity of or retiring approximately $3.0 billion of debt.

Availability of borrowings under our RBL Facility is an important source of liquidity for us. Our current RBL Facility will mature in May 2019 and has a borrowing base subject to semi-annual redetermination. In October 2017, our RBL borrowing base was affirmed at $1.4 billion and is currently $1.36 billion as a result of our January 2018 debt exchange. Downward revisions of our oil and natural gas reserves volume and value due to declines in commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, sales of assets, or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base in the future, and these reductions could be significant. Conversely, future acquisitions, reserve additions and higher prices may have the effect of increasing our borrowing base.

During 2017, as it relates to our RBL Facility, we extended our first lien debt to EBITDAX covenant through March 31, 2019, and the ratio was reduced to 3.0 to 1.0. As of December 31, 2017, we were in compliance with our debt covenants, with a ratio of first lien debt to EBITDAX of 0.86x. In April 2019, this financial covenant will revert to a requirement that our total debt to EBITDAX ratio not exceed 4.5 to 1.0. As of December 31, 2017, our ratio of total net debt to EBITDAX was 5.88x. We are currently working to renew and extend the maturity of the facility as well as the required covenants thereunder. Under our debt agreements, we are limited in non-RBL Facility debt repurchases. As of December 31, 2017, the non-RBL Facility debt repurchases limit was approximately $885 million. On January 3, 2018 we entered into a new debt agreement with the new 2024 senior secured note holders that reduced the non-RBL Facility debt repurchases limit to $225 million subject to certain customary adjustments. This limitation does not apply to debt repurchases completed using proceeds from dispositions.

During 2017, we entered into transactions to enhance capital efficiency and pursue acquisitions while doing so in a cash or leverage enhancing manner, including (i) entering into two drilling joint ventures in the Altamont and Permian basin and (ii) entering into our largest acquisition agreement to date in December 2017 in the Eagle Ford for approximately $245 million, while at the same time (iii) entering into an agreement to divest certain assets in Altamont for approximately $180 million, subject to customary closing adjustments. We closed the acquisition in January 2018, and closed the sale in February 2018.

To protect our cash flows and preserve our liquidity, we enter into derivative contracts on a substantial portion of our anticipated future production volumes. As of December 31, 2017, we have derivative contracts (swaps, collars, three-way collars) on 13.6 MMBbls of our anticipated 2018 oil production at a weighted average floor price of $58.68 per barrel of oil. Approximately two-thirds of these crude oil contracts also allow for upside participation (to a weighted average price of approximately $68.15 per barrel) if prices move above current strip prices. Additionally, our 2018 three-way collar contracts contain certain sub-floor prices (weighted average prices of $50 per barrel) that limit the amount of our derivative settlements under these three-way contracts should prices drop below the sub-floor prices. For 2018 and 2019, we also have derivative swap contracts on 26 TBtu and 7 TBtu of our anticipated natural gas production at a weighted average price of $3.04 and $2.97 per MMBtu, respectively. Based on the mid-point of our forecasted 2018 guidance, our oil and natural gas derivative contracts provide price protection on approximately 81% and 56%, respectively, of our anticipated 2018 oil and natural gas production. See "Our Business" for further information on our derivative instruments.

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In 2018, we expect to spend approximately $600 million to $650 million in capital (not including acquisition capital) in our programs. Based upon our current price and cost assumptions and our hedge program, we believe that our current capital program will exceed our estimated operating cash flows after interest payments. Our capital program and Eagle Ford acquisition should, however, provide increases to our cash flow when combined with increased capital efficiencies. We believe the borrowing capacity under our RBL Facility together with expected cash flows from our operations will be sufficient to fund our capital program and meet current obligations and projected working capital requirements through the next twelve months.

Our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the RBL Facility, (ii) repay or refinance any of our indebtedness on commercially reasonable terms or at all, or (iii) obtain additional capital if
required on acceptable terms or at all to fund our capital programs or any potential future acquisitions, joint ventures or other
similar transactions, will depend on prevailing economic conditions many of which are beyond our control. The ongoing volatility in the energy industry and in commodity prices will likely continue to impact our outlook. Our plans are intended to address the impacts of the current volatility in commodity prices while (i) maintaining sufficient liquidity to fund capital in our drilling programs, (ii) meeting our debt maturities, and (iii) managing and working to strengthen our balance sheet. We will continue to be opportunistic and aggressive in managing our cost structure and in turn, our liquidity, to meet our capital and operating needs. Accordingly, we will continue to pursue cost saving measures where possible to optimize our capital program, and reduce operating and general and administrative costs, which may include renegotiating contracts with contractors, suppliers and service providers, deferring and eliminating various discretionary costs, and/or reducing the number of staff and contractors, if necessary.

To the extent commodity prices decline, or we experience disruptions in the financial markets impacting our longer-term access to them or that affect our cost of capital, our ability to fund future growth projects may be further impacted. We continually monitor the capital markets and our capital structure and make changes from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. For example, we could (i) elect to continue to repurchase additional amounts of our outstanding debt in the future for cash through open market repurchases or privately negotiated transactions with certain of our debtholders subject to the limitations in our RBL Facility or (ii) issue additional secured debt as permitted under our debt agreements, although there is no assurance we would do so. It is possible that additional adjustments to our plan and outlook may occur based on market conditions and the needs of the Company at that time, which could include selling assets, liquidating all or a portion of our hedge portfolio, seeking additional partners to develop our assets, issuing equity, and/or further reducing our planned capital spending program.

Capital Expenditures. Our capital expenditures and average drilling rigs for the twelve months ended December 31, 2017 were:

	Capital Expenditures(1) (in millions)	Average Drilling Rigs
Eagle Ford Shale	$ 227	1.3
Permian(2)	267	1.6
Altamont	93	1.8
Total	$ 587	4.7

(1) Represents accrual-based capital expenditures.
(2) Includes approximately $29 million of acquisition capital.

Debt. As of December 31, 2017, our total debt was approximately $4.1 billion, of which $21 million is due in 2018. Our overall debt is comprised of $29 million in senior secured term loans with maturity dates in 2018 and 2019, $595 million outstanding under the RBL Facility which matures in 2019, $2.0 billion in senior unsecured notes due in 2020, 2022 and 2023, and $1.5 billion in senior secured notes due in 2024 and 2025. In January 2018, we exchanged $954 million, $54 million and $139 million of the outstanding amount of our senior unsecured notes due in 2020, 2022 and 2023, respectively, for $1.1 billion senior secured notes due in 2024. For additional details on our long-term debt, see Liquidity and Capital Resources above and including restrictive covenants under our debt agreements, see Part II, Item 8, “Financial Statements and Supplementary Data”, Note 8.

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Overview of Cash Flow Activities. Our cash flows are summarized as follows:

	Year ended December 31,		
	2017	2016	2015
		(in millions)	
Cash Inflows			
Operating activities			
Net loss	$(194)	$ (27)	$(3,748)
Impairment charges	2	2	4,299
Gain on sale of assets	—	(78)	—
Loss (gain) on extinguishment of debt	16	(384)	41
Other income adjustments	487	498	456
Change in assets and liabilities	64	773	279
Total cash flow from operations	$375	$ 784	$1,327
Investing activities			
Proceeds from the sale of assets	$—	$ 389	$1
Deposit received in advance of divestiture	18	—	—
Cash inflows from investing activities	$18	$ 389	$1
Financing activities			
Proceeds from issuance of long-term debt	1,930	1,195	2,067
Cash inflows from financing activities	$1,930	$ 1,195	$2,067
Total cash inflows	$2,323	$ 2,368	$3,395
Cash Outflows			
Investing activities			
Cash paid for capital expenditures	$541	$ 533	$1,433
Cash paid for acquisitions	29	—	111
Deposit paid in advance of acquisition	25	—	—
Cash outflows from investing activities	$595	$ 533	$1,544
Financing activities			
Repayments and repurchases of long-term debt	$1,679	$ 1,804	$1,826
Debt issue costs	21	34	20
Other	3	3	1
Cash outflows from financing activities	$1,703	$ 1,841	$1,847
Total cash outflows	$2,298	$ 2,374	$3,391
Net change in cash, cash equivalents and restricted cash	$25	$ (6)	$4

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Contractual Obligations

We are party to various contractual obligations. Some of these obligations are reflected in our financial statements, such as liabilities from financing obligations and commodity-based derivative contracts, while other obligations, such as operating leases and capital commitments, are not presently reflected on our consolidated balance sheet. The following table and discussion summarizes our contractual cash obligations as of December 31, 2017, for each of the periods presented:

	2018	2019-2020	2021-2022	Thereafter	Total
			(in millions)		
Financing obligations:					
Principal	$21	$ 1,803	$ 250	$ 2,019	$4,093
Interest	314	506	338	262	1,420
Liabilities from derivatives	17	—	—	—	17
Operating leases	5	10	11	16	42
Other contractual commitments and purchase obligations:					
Volume and transportation commitments	64	119	92	7	282
Other obligations	39	15	—	—	54
Total contractual obligations	$460	$ 2,453	$ 691	$ 2,304	$5,908

Financing Obligations (Principal and Interest). Debt obligations included in the table above represent stated maturities. Interest payments are shown through the stated maturity date of the related debt based on (i) the contractual interest rate for fixed rate debt and (ii) current market interest rates and the contractual credit spread for variable rate debt. See Part II, Item 8, "Financial Statements and Supplementary Data", Note 8 for more information on the maturities of our long-term debt. Subsequent to December 31, 2017, we exchanged $954 million, $54 million and $139 million of the outstanding amount of our senior unsecured notes shown above, maturing in 2020, 2022 and 2023, respectively, for $1,092 million senior secured notes maturing in 2024.

Liabilities from Derivatives. These amounts include the fair value of our commodity-based and interest rate derivative liabilities.

Operating Leases. Amounts include leases related to our office space and various equipment.

Other Contractual Commitments and Purchase Obligations. Other contractual commitments and purchase obligations are legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions. Amounts in the schedule above approximate the timing of the underlying obligations. Included are the following:

- Volume and Transportation Commitments. Included in these amounts are commitments for demand charges for firm access to natural gas transportation, volume deficiency contracts and firm oil capacity contracts.
- Other Obligations. Included in these amounts are commitments for drilling, completions and seismic activities for our operations and various other maintenance, engineering, information technology, procurement and construction contracts. Our future commitments under these contracts may change reflecting changes in commodity prices and any related effect on the supply/demand for these services. We have excluded asset retirement obligations and reserves for litigation and environmental remediation, as these liabilities are not contractually fixed as to timing and amount.

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Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Part II, Item 8, “Financial Statements and Supplementary Data”, Note 9.

Off-Balance Sheet Arrangements

We have no investments in unconsolidated entities or persons that could materially affect our liquidity or the availability of capital resources. We do not have any off-balance sheet arrangements that have, or are reasonably likely to have, a material effect on our financial condition or results of operations.

Critical Accounting Estimates

Our significant accounting policies are described in Part II, Item 8, "Financial Statements and Supplementary Data", Note 1 of our consolidated financial statements included elsewhere in this Annual Report on Form 10-K. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenue and expense and the disclosures of contingent assets and liabilities. We consider our critical accounting estimates to be those estimates that require complex or subjective judgment in the application of the accounting policy and that could significantly impact our financial results based on changes in those judgments. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. Our management has identified the following critical accounting estimates:

Accounting for Oil and Natural Gas Producing Activities. We apply the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, non-drilling exploratory costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred while acquisition costs, development costs and the costs of drilling and completing wells are capitalized. If a well is exploratory in nature, such costs are capitalized, pending the determination of proved oil and natural gas reserves. As a result, at any point in time, we may have capitalized costs on our consolidated balance sheet associated with exploratory wells that may be charged to exploration expense in a future period. Costs of drilling exploratory wells that do not result in proved reserves are expensed. Under the successful efforts method, we also capitalize salaries and benefits that we determine are directly attributable to our oil and natural gas activities. Depreciation, depletion, amortization and the impairment of oil and natural gas properties is calculated on a depletable unit basis based on estimates of proved quantities of proved oil and natural gas reserves. Revisions to these estimates can alter our depletion rates in the future and affect our future depletion expense or assessment of impairment.

We evaluate capitalized costs related to proved properties at least annually or upon a triggering event (such as a significant decline in forward commodity prices or change in development plans, among other items) to determine if impairment of such properties has occurred. Our evaluation of whether costs are recoverable is made based on common geological structure or stratigraphic conditions (for example, we evaluate proved property for impairment separately for each of our operating areas), and the evaluation considers estimated future cash flows for all proved developed (producing and non-producing), proved undeveloped reserves and risk-weighted non-proved reserves in comparison to the carrying amount of the proved properties. Important assumptions in the determination of these cash flows are estimates of future oil and gas production, estimated forward commodity prices as of the date of the estimate, adjusted for geographical location and contractual and quality differentials and estimates of future operating and development costs. If the carrying amount of a property exceeds the estimated undiscounted future cash flows of its reserves, the carrying amount is reduced to estimated fair value through a charge to income. Fair value is calculated by discounting those estimated future cash flows using a risk-adjusted discount rate. The discount rate is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying crude oil and natural gas. Each of these estimates involves a high degree of judgment.

As of December 31, 2017, our capitalized costs related to proved properties were approximately $1,290 million in Eagle Ford, $1,907 million in the Permian basin and $1,132 million in Altamont.

Capitalized costs associated with unproved properties (e.g., leasehold acquisition costs associated with non-producing areas) are also assessed for impairment based on estimated drilling plans and capital expenditures which may also change relative to forward commodity prices and/or potential lease expirations. Generally, economic recovery of unproved reserves in non-producing areas are not yet supported by actual production or conclusive formation tests, but must be confirmed by continued exploration and development activities. Our allocation of capital to the development of unproved properties may be influenced by changes in commodity prices (e.g., a low oil price environment), the availability of oilfield services and the relative returns of our unproved property development in comparison to the use of capital for other strategic objectives.

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For example, in the Permian we have drilling commitments that obligate us to drill a specific number of wells in order to hold all of our acreage. In 2016, we amended our Consolidated Drilling and Development Unit Agreement with the University of Texas Land System in the Permian basin to provide flexibility to extend the time frame to hold our acreage by nearly four years to the end of 2021, with an increase in annual well completion requirements from six wells per year to 34, 55 and 55 wells per year in 2016, 2017 and 2018, respectively. We fulfilled this requirement in 2016 and 2017. Among other factors, should future oil prices not justify sufficient capital allocation to the continued development of these unproved properties, we could incur impairment charges of our unproved property in the future. Our unproved property costs were approximately $66 million at December 31, 2017, all of which was associated with the Permian basin.

Estimates of proved reserves reflect quantities of oil, natural gas and NGLs which geological and engineering data demonstrate, with reasonable certainty, will be recoverable in future years from known reservoirs under existing economic conditions. These estimates of proved oil and natural gas reserves primarily impact our property, plant and equipment amounts on our balance sheets and the depreciation, depletion and amortization amounts, including any impairment charges, on our consolidated income statements, among other items. The process of estimating oil and natural gas reserves is complex and requires significant judgment to evaluate all available geological, geophysical engineering and economic data. Our proved reserves are estimated at a property level and compiled for reporting purposes by a centralized group of experienced reservoir engineers who work closely with the operating groups. These engineers interact with engineering and geoscience personnel in each of our areas and accounting and marketing personnel to obtain the necessary data for projecting future production, costs, net revenues and economic recoverable reserves. Reserves are reviewed internally with senior management quarterly and presented to the board of directors, in summary form on an annual basis. Additionally, on an annual basis each property is reviewed in detail to evaluate forecasts of operating expenses, netback prices, production trends and development timing to ensure they are reasonable. Our proved reserves are reviewed by internal committees and the processes and controls used for estimating our proved reserves are reviewed by our internal auditors. In addition, a third-party reservoir engineering firm, which is appointed by and reports to the Audit Committee of the board of directors, conducts an audit of the estimates of a substantial portion of our proved reserves.

As of December 31, 2017, 44% of our total proved reserves were undeveloped and 3% were developed, but non-producing. The data for a given field may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. In addition, the subjective decisions and variances in available data for various fields increase the likelihood of significant changes in these estimates.

Derivatives. We record derivative instruments at their fair values. We estimate the fair value of our derivative instruments using exchange prices, third-party pricing quotes, interest rates, data and valuation techniques that incorporate specific contractual terms, derivative modeling techniques and present value concepts. One of the primary assumptions used to estimate the fair value of commodity-based derivative instruments is price. Our pricing assumptions are based upon price curves derived from actual prices observed in the market, pricing information supplied by a third-party valuation specialist and independent pricing sources and models that rely on this forward pricing information. The extent to which we rely on pricing information received from third parties in developing these assumptions is based, in part, on whether the information considers the availability of observable data in the marketplace. For example, in relatively illiquid markets we may make adjustments to the pricing information we receive from third parties based on our evaluation of whether third party market participants would use pricing assumptions consistent with these sources.

The table below presents the hypothetical sensitivity of our commodity-based derivatives to changes in fair values arising from immediate selected potential changes in oil and natural gas prices at December 31, 2017:

		Change in Price	
		10 Percent Increase	10 Percent Decrease
	Fair Value	Fair Value Change	Fair Value Change
		(in millions)	

Commodity-based derivatives—net assets (liabilities)	$ 5	$ (65)	$ (70)	$ 78	$ 73

Other significant assumptions that we use in determining the fair value of our derivative instruments are those related to credit and non-performance risk. We adjust the fair value of our derivative assets based on our counterparty's creditworthiness and the risk of non-performance. These adjustments are based on applicable credit ratings, bond yields, changes in actively traded credit default swap prices (if available) and other information related to non-performance and credit standing.

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Deferred Taxes and Uncertain Income Tax Positions. We record deferred income tax assets and liabilities reflecting the tax consequences of differences between the financial statement carrying value of assets and liabilities and the tax basis of those assets and liabilities. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. Our deferred tax assets and liabilities reflect our conclusions about which positions are more likely than not to be sustained if they are audited by taxing authorities. Uncertain tax positions, including deductions or other positions taken on our tax returns, involve the exercise of significant judgment which could change or be challenged by taxing authorities and could impact our financial condition or results of operations.

Valuation Allowances. We assess the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of existing deferred tax assets. When it is more likely than not that we will not be able to realize all or a portion of such asset, we record a valuation allowance. Based upon the evaluation of the available evidence, we maintained a valuation allowance against our net deferred tax assets of $644 million as of December 31, 2017. We evaluate our valuation allowances each reporting period and the level of such allowance will change as our deferred tax balances change. Key estimates and assumptions include expectations of future taxable income, the ability and our intent to undertake transactions that will allow us to realize the asset, all of which involve judgment. Changes in these estimates or assumptions can have a significant effect on our operating results.

ITEM 7A. Qualitative and Quantitative Disclosures About Market Risk

We are exposed to market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to and examples of each are:

Commodity Price Risk

- changes in oil, natural gas and NGLs prices impact the amounts at which we sell our production and affect the fair value of our oil and natural gas derivative contracts; and
- changes in locational price differences also affect amounts at which we sell our oil, natural gas and NGLs production, and the fair values of any related derivative products.

Interest Rate Risk

- changes in interest rates affect the interest expense we incur on our variable-rate debt and the fair value of fixed-rate debt; and
- changes in interest rates used to discount liabilities result in higher or lower recorded amount of liabilities and accretion expense over time.

Risk Management Activities

Where practical, we manage commodity price risks by entering into contracts involving physical or financial settlement that attempt to limit exposure related to future market movements on our cash flows. The timing and extent of our risk management activities are based on a number of factors, including our market outlook, risk tolerance and liquidity. Our risk management activities typically involve the use of the following types of contracts:

- forward contracts, which commit us to purchase or sell energy commodities in the future;
- option contracts, which convey the right to buy or sell a commodity, financial instrument or index at a predetermined price;
- swap contracts, which require payments to or from counterparties based upon the differential between two prices or rates for a predetermined contractual (notional) quantity; and
- structured contracts, which may involve a variety of the above characteristics.

Many of the contracts we use in our risk management activities qualify as derivative financial instruments. A discussion of our accounting policies for derivative instruments is included in Part II Item 8, "Financial Statements and Supplementary Data", Notes 1 and 6.

For information regarding changes in commodity prices and interest rates during 2017, please see Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations”.

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Commodity Price Risk

Oil, Natural Gas and NGLs Derivatives. We attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of oil and natural gas production through the use of derivative oil and natural gas swaps, basis swaps and option contracts. These contracts impact our earnings as the fair value of these derivatives changes. Our derivatives do not mitigate all of the commodity price risks of our forecasted sales of oil and natural gas production and, as a result, we are subject to commodity price risks on our remaining forecasted production.

Sensitivity Analysis. The table below presents the change in fair value of our commodity-based derivatives due to hypothetical changes in oil and natural gas prices, discount rates and credit rates at December 31, 2017:

		Oil, Natural Gas and NGLs Derivatives			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Price impact[1]	$ 5	$ (65)	$ (70)	$ 78	$ 73

		Oil, Natural Gas and NGLs Derivatives			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Discount Rate[2]	$ 5	$ 5	$ —	$ 5	$ —
Credit rate[3]	$ 5	$ 5	$ —	$ 5	$ —

(1) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in fair values arising from changes in oil, natural gas and NGLs prices.

(2) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in the discount rates we used to determine the fair value of our derivatives.

(3) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in credit risk of our counterparties

Interest Rate Risk

Certain of our debt agreements are sensitive to changes in interest rates. The table below shows the maturity of the carrying amounts and related weighted-average effective interest rates on our long-term interest-bearing debt by expected maturity date as well as the total fair value of the debt. The fair value of our long-term debt has been estimated primarily based on quoted market prices for the same or similar issues.

	December 31, 2017								December 31, 2016	
	Expected Fiscal Year of Maturity of Carrying Amounts							Fair	Carrying	Fair
	2018	2019	2020	2021	2022	Thereafter	Total	Value	Amounts	Value
					(in millions)					
Fixed rate long-term debt	$—	$—	$1,200	$ —	$250	$2,019	$3,469	$2,644	$2,877	$2,630
Average interest rate	8.2 %	8.2 %	7.9 %	7.6 %	7.6 %	7.9 %				
Variable rate long-term debt	$21	$603	$—	$ —	$—	$—	$624	$623	$979	$1,007
Average interest rate	4.8 %	4.8 %	— %	— %	— %	— %				

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

Below is an index to the items contained in Part II, Item 8, Financial Statements and Supplementary Data

Schedules

All financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the financial statements or related notes thereto.

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MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined by SEC rules adopted under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is 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. It consists of policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we made an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2017. In making this assessment, we used the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2017. The effectiveness of our internal control over financial reporting as of December 31, 2017 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report included herein.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
EP Energy Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of EP Energy Corporation (the Company) as of December 31, 2017 and 2016, the related consolidated statements of income, cash flows and changes in equity for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control- Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 1, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2006.

Houston, Texas
March 1, 2018

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
EP Energy Corporation

Opinion on Internal Control over Financial Reporting

We have audited EP Energy Corporation’s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control- Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, EP Energy Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2017 and 2016, the related consolidated statements of income, cash flows and changes in equity for each of the three years in the period ended December 31, 2017, and the related notes and our report dated March 1, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management’s Annual 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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Houston, Texas
March 1, 2018

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EP ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per common share amounts)

	Year Ended December 31,		
	2017	2016	2015
Operating revenues			
Oil	$812	$653	$981
Natural gas	110	122	200
NGLs	103	65	60
Financial derivatives	41	(73)	667
Total operating revenues	1,066	767	1,908
Operating expenses			
Oil and natural gas purchases	2	10	31
Transportation costs	115	109	116
Lease operating expense	163	159	186
General and administrative	81	146	148
Depreciation, depletion and amortization	487	462	983
Gain on sale of assets	—	(78)	—
Impairment charges	2	2	4,299
Exploration and other expense	12	5	20
Taxes, other than income taxes	65	50	80
Total operating expenses	927	865	5,863
Operating income (loss)	139	(98)	(3,955)
(Loss) gain on extinguishment of debt	(16)	384	(41)
Interest expense	(326)	(312)	(330)
Loss before income taxes	(203)	(26)	(4,326)
Income tax benefit (expense)	9	(1)	578
Net loss	$(194)	$(27)	$(3,748)
Basic and diluted net income (loss) per common share			
Net loss	$(0.79)	$(0.11)	$(15.37)
Basic and diluted weighted average common shares outstanding	246	245	244

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 27	$ 20
Restricted cash	18	—
Accounts receivable		
Customer, net of allowance of less than $1 in 2017 and 2016	158	133
Other, net of allowance of $1 in 2017 and 2016	13	16
Income tax receivable	9	—
Materials and supplies	16	16
Derivative instruments	18	58
Assets held for sale	172	—
Prepaid assets	35	5
Total current assets	466	248
Property, plant and equipment, at cost		
Oil and natural gas properties	7,532	7,194
Other property, plant and equipment	69	85
	7,601	7,279
Less accumulated depreciation, depletion and amortization	3,179	2,781
Total property, plant and equipment, net	4,422	4,498
Other assets		
Derivative instruments	4	4
Unamortized debt issue costs on revolving credit facility	6	10
Other	2	1
	12	15
Total assets	$ 4,900	$ 4,761

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 88	$ 63
Other	158	113
Derivative instruments	17	4
Accrued interest	62	43
Liabilities related to assets held for sale	2	—
Short-term debt, net of debt issue costs	21	—
Other accrued liabilities	100	98
Total current liabilities	448	321
Long-term debt, net of debt issue costs	4,022	3,789
Other long-term liabilities		
Derivative instruments	—	1
Asset retirement obligations	33	40
Other	5	4
Total non-current liabilities	4,060	3,834
Commitments and contingencies (Note 9)		
Stockholders' equity		
Class A shares, $0.01 par value; 550 million shares authorized; 252 million shares issued and outstanding at December 31, 2017; 251 million shares issued and outstanding at December 31, 2016	3	2
Class B shares, $0.01 par value; 0.3 million and 0.8 million shares authorized, issued and outstanding at December 31, 2017 and December 31, 2016	—	—
Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding	—	—
Treasury stock (at cost); 0.7 million shares at December 31, 2017 and 0.5 million shares at December 31, 2016	(3)	(3)
Additional paid-in capital	3,526	3,546
Accumulated deficit	(3,134)	(2,939)
Total stockholders' equity	392	606
Total liabilities and equity	$ 4,900	$ 4,761

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2017	2016	2015
Cash flows from operating activities			
Net loss	$(194)	$(27)	$(3,748)
Adjustments to reconcile net loss to net cash provided by operating activities			
Depreciation, depletion and amortization	487	462	983
Gain on sale of assets	—	(78)	—
Deferred income tax benefit	—	—	(578)
Impairment charges	2	2	4,299
Loss (gain) on extinguishment of debt	16	(384)	41
Share-based compensation expense	(19)	17	19
Non-cash portion of exploration expense	5	2	14
Amortization of debt issuance costs	14	16	18
Other non-cash income items	—	1	—
Asset and liability changes			
Accounts receivable	(22)	71	55
Accounts payable	55	(22)	(70)
Derivative instruments	52	714	277
Accrued interest	19	(4)	(6)
Other asset changes	(16)	8	22
Other liability changes	(24)	6	1
Net cash provided by operating activities	375	784	1,327
Cash flows from investing activities			
Cash paid for capital expenditures	(541)	(533)	(1,433)
Proceeds from the sale of assets	—	389	1
Cash paid for acquisitions	(29)	—	(111)
Deposit paid in advance of acquisition	(25)	—	—
Deposit received in advance of divestiture	18	—	—
Net cash used in investing activities	(577)	(144)	(1,543)
Cash flows from financing activities			
Proceeds from issuance of long-term debt	1,930	1,195	2,067
Repayments and repurchases of long-term debt	(1,679)	(1,804)	(1,826)
Debt issue costs	(21)	(34)	(20)
Other	(3)	(3)	(1)
Net cash provided by (used in) financing activities	227	(646)	220
Change in cash, cash equivalents and restricted cash	25	(6)	4
Cash, cash equivalents and restricted cash - beginning of period	20	26	22
Cash, cash equivalents and restricted cash - end of period	$45	$20	$26
Supplemental cash flow information			
Interest paid, net of amounts capitalized	$291	$293	$312

Income tax payments (refunds)	1	(2)	(22)

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(In millions)

	Class A Stock		Class B Stock					
	Shares	Amount	Shares	Amount	Treasury Stock	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total
Balance at December 31, 2014	245	$ 2	0.8	$ —	$ —	$ 3,510	$ 836	$ 4,348
Share-based compensation	3	—	—	—	—	19	—	19
Net loss	—	—	—	—	—	—	(3,748)	(3,748)
Balance at December 31, 2015	248	$ 2	0.8	$ —	$ —	$ 3,529	$ (2,912)	$ 619
Share-based compensation	3	—	—	—	(3)	17	—	14
Net loss	—	—	—	—	—	—	(27)	(27)
Balance at December 31, 2016	251	$ 2	0.8	$ —	$ (3)	$ 3,546	$ (2,939)	$ 606
Cumulative effect of accounting change	—	—	—	—	—	1	(1)	—
Balance at January 1, 2017	251	$ 2	0.8	$ —	$ (3)	$ 3,547	$ (2,940)	606
Share-based compensation	1	1	(0.5)	—	—	(21)	—	(20)
Net loss	—	—	—	—	—	—	(194)	(194)
Balance at December 31, 2017	252	$ 3	0.3	$ —	$ (3)	$ 3,526	$ (3,134)	$ 392

See accompanying notes.

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EP ENERGY CORPORATION
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation and Consolidation

Our consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (U.S. GAAP) and include the accounts of all consolidated subsidiaries after the elimination of all significant intercompany accounts and transactions.

We consolidate entities when we have the ability to control the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment.

We are engaged in the exploration for and the acquisition, development, and production of oil, natural gas and NGLs in the United States. Our oil and natural gas properties are managed as a single operating segment rather than through discrete operating segments or business units. We track basic operational data by area and allocate capital resources on a project-by-project basis across our entire asset base without regard to individual areas. We assess financial performance as a single enterprise and not on a geographical area basis.

New Accounting Pronouncements Issued But Not Yet Adopted

The following accounting standards have been issued but not yet been adopted.

Leases. In February 2016, the FASB issued ASU No. 2016-02, Leases, which requires lessees to recognize lease assets and lease liabilities on the balance sheet and disclose key information about leasing arrangements. Adoption of this
standard is required beginning in the first quarter of 2019 and early adoption is allowed. We continue to evaluate our contracts and other agreements to assess the impact this update will have on our financial statements.

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which clarifies the principles for recognizing revenue and develops a common revenue standard for U.S. GAAP and International Financial Reporting Standards. Adoption of this standard is required beginning in the first quarter of 2018. Modified or full retrospective application of this standard is required upon adoption. We do not anticipate our adoption of this standard on January 1, 2018, utilizing the modified retrospective approach, will have a material impact on our financial statements, disclosure requirements, accounting policies, business processes and/or related controls.

Significant Accounting Policies

Use of Estimates

The preparation of our financial statements requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

Revenue Recognition

Our revenues are generated primarily through the physical sale of oil, natural gas and NGLs to third party customers at spot or market prices under both short and long-term contracts. We recognize revenue upon delivery and transfer of control of the product to the customer which occurs at the point in time which delivery and passage of title and risk of loss have occurred. Delivery and transfer of control vary depending on the product and delivery method but typically occurs at a pipeline or gathering line delivery point interconnect when delivered via pipeline or at the wellhead or tank battery to purchasers who transport the oil via truck. Revenue is measured and based upon index prices (WTI, LLS, Henry Hub and Mt. Belvieu) or refiners' posted prices at various delivery points across our producing basins. Realized prices received (not considering the effects of hedges) are generally less than the stated index price as a result of contractual deductions, differentials from the index to the delivery point, adjustments for time, and/or discounts for quality or grade.

Revenue is recorded using the sales method, net of any royalty interests or other profit interests in the produced product. Revenues related to products delivered, but not yet billed, are estimated each month. These estimates are based on contract data, commodity prices and preliminary throughput and allocation measurements. When actual sales volumes exceed our entitled share of sales volumes, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability.

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Costs associated with the transportation and delivery of production between the wellhead and its intended sale location are generally included in transportation costs. We also purchase and sell oil and natural gas on a monthly basis to manage our overall oil and natural gas production and sales. These transactions are undertaken to optimize prices we receive for our oil and natural gas, to physically move oil and gas to its intended sales point, or to manage firm transportation agreements. Revenue related to these transactions are recorded in oil and natural gas sales in operating revenues and associated purchases reflected in oil and natural gas purchases in operating expenses in our consolidated income statements.

For the years ended December 31, 2017, 2016 and 2015, we had two customers that individually accounted for 10 percent or more of our total revenues. The loss of any one customer would not have an adverse effect on our ability to sell our oil, natural gas and NGLs production.

While most of our physical production is priced off of market indices, we actively manage the volatility of market pricing through our risk management program whereby we enter into financial derivatives contracts. All of our derivatives are marked-to-market each period. The change in the fair value of our commodity-based derivatives, as well as any realized amounts, are reflected in operating revenues as financial derivative revenues (see Derivatives below and Note 6).

Cash and Cash Equivalents and Restricted Cash

We consider short-term investments with an original maturity of less than three months to be cash equivalents. As of December 31, 2017, we had $18 million in restricted cash reflecting a deposit received in advance of the divestiture of certain assets. As of December 31, 2016, we had no restricted cash.

As a result of early adopting ASU No. 2016-15, Statement of Cash Flows - Classification of Certain Cash Receipts and Cash Payments and ASU No. 2016-18, Statement of Cash Flows - Restricted Cash as of December 31, 2017 our consolidated statement of cash flows for all historical periods reflect restricted cash combined with cash and cash equivalents. We did not have any other material impact of early adopting these ASUs.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable and for natural gas imbalances with other parties if we determine that we will not collect all or part of the outstanding balance. We regularly review collectability and establish or adjust our allowance as necessary using the specific identification method.

Oil and Natural Gas Properties

We account for oil and natural gas properties in accordance with the successful efforts method of accounting for oil and natural gas exploration and development activities.

Under the successful efforts method, we capitalize (i) lease acquisition costs, all development costs and exploratory drilling costs until results are determined, (ii) certain internal costs directly identified with the acquisition, successful drilling of exploratory wells and development activities, and (iii) interest costs related to financing oil and natural gas projects actively being developed until the projects are evaluated or substantially complete and ready for their intended use if the projects were evaluated as successful. Non-drilling exploratory costs, including certain geological and geophysical costs such as seismic costs and delay rentals, are expensed as incurred.

We provide for depreciation, depletion, and amortization on the basis of common geological structure or stratigraphic conditions applied to total capitalized costs, plus future abandonment costs, net of salvage value, using the unit of production method. Lease acquisition costs are amortized over total proved reserves, while other exploratory drilling and all developmental costs are amortized over total proved developed reserves.

We evaluate capitalized costs related to proved properties upon a triggering event to determine if impairment of such properties is necessary. Our evaluation of recoverability is made on the basis of common geological structure or stratigraphic conditions and considers estimated future cash flows primarily from all proved developed (producing and non-producing) and proved undeveloped reserves in comparison to the carrying amount of the proved properties. Estimated future cash flows are determined based on estimates of future oil and gas production, estimated or published commodity prices as of the date of the estimate, adjusted for geographical location, contractual and quality price differentials, and estimates of future operating and development costs. If the carrying amount of a property exceeds these estimated undiscounted future cash flows, the carrying amount is reduced to its estimated fair value through a charge to income. Fair value is calculated by discounting the estimated future cash flows using a risk-adjusted discount rate. This discount rate is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying crude oil and natural gas. Leasehold acquisition costs associated with non-producing areas are also assessed for impairment based on our estimated drilling plans and anticipated capital expenditures related to potential lease expirations.

Property, Plant and Equipment (Other than Oil and Natural Gas Properties)

Our property, plant and equipment, other than our assets accounted for under the successful efforts method, are recorded at their original cost of construction or, upon acquisition, at the fair value of the assets acquired. We capitalize the major units of property replacements or improvements and expense minor items. We depreciate our non-oil and natural gas property, plant and equipment using the straight-line method over the useful lives of the assets which range from four to 15 years.

Accounting for Asset Retirement Obligations

We record a liability for legal obligations associated with the replacement, removal or retirement of our long-lived assets in the period the obligation is incurred and is estimable. Our asset retirement liabilities are initially recorded at their estimated fair value with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the useful life of the asset to which that liability relates. An ongoing expense is recognized for changes in the value of the liability as a result of the passage of time, which we record as depreciation, depletion and amortization expense in our consolidated income statements.

Accounting for Long-Term Incentive Compensation

We measure the cost of long-term incentive compensation based on the fair value of the award on the day it is granted. Awards issued under our incentive compensation programs are recognized as either equity awards or liability awards based on their characteristics. Expense is recognized in our consolidated financial statements as general and administrative expense over the period of service required by the award. As a result of adopting ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting, as of January 1, 2017, we recorded a cumulative adjustment of approximately $1 million to the opening balance of retained earnings related to our election to begin accounting for forfeitures in compensation cost when they occur rather than estimating them over the service period. See Note 10 for further discussion of our long-term incentive compensation.

Environmental Costs, Legal and Other Contingencies

Environmental Costs. We record environmental liabilities at their undiscounted amounts on our consolidated balance sheet in other current and long-term liabilities when we assess that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our environmental liabilities are based on current available facts, existing technology and presently enacted laws and regulations, taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and expense costs that do not in general and administrative expense.

We evaluate any amounts paid directly or reimbursed by government sponsored programs and potential recoveries or reimbursements of remediation costs from third parties, including insurance coverage, separately from our liability. Recovery is evaluated based on the creditworthiness or solvency of the third party, among other factors. When recovery is assured, we record and report an asset separately from the associated liability on our consolidated balance sheet.

Legal and Other Contingencies. We recognize liabilities for legal and other contingencies when we have an exposure that indicates it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other to occur, the low end of the range is accrued.

Derivatives

We enter into derivative contracts on our oil and natural gas products primarily to stabilize cash flows and reduce the risk and financial impact of downward commodity price movements on commodity sales. Derivative instruments are reflected on our consolidated balance sheet at their fair value as assets and liabilities. We classify our derivatives as either current or non-current based on their anticipated settlement date. We net derivative assets and liabilities with counterparties where we have a legal right of offset.

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All of our derivatives are marked-to-market each period and changes in the fair value of our commodity based derivatives, as well as any realized amounts, are reflected as operating revenues. We classify cash flows related to derivative contracts based on the nature and purpose of the derivative. As the derivative cash flows are considered an integral part of our oil and natural gas operations, they are classified as cash flows from operating activities. In our consolidated balance sheet, receivables and payables resulting from the settlement of our derivative instruments are reported as trade receivables and payables. See Note 6 for a further discussion of our derivatives.

Income Taxes

We record current income taxes based on our estimates of current taxable income and provide for deferred income taxes to reflect estimated future income tax payments and receipts. Changes in tax laws are recorded in the period they are enacted. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We classify all deferred tax assets and liabilities, along with any related valuation allowance, as non-current on the consolidated balance sheet. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. The realization of our deferred tax assets depends on recognition of sufficient future taxable income during periods in which those temporary differences are deductible. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances. In evaluating our valuation allowances, we consider cumulative book losses, the reversal of existing temporary differences, the existence of taxable income in carryback years, tax planning strategies and future taxable income for each of our taxable jurisdictions, the latter two of which involve the exercise of significant judgment. Changes to our valuation allowances could materially impact our results of operations.

2. Acquisitions and Divestitures

Acquisitions. In 2017, we acquired proved and unproved properties for approximately $29 million located in the Permian basin. In December 2017, we entered into an agreement to acquire certain producing properties and undeveloped acreage in Eagle Ford for approximately $245 million, subject to customary closing adjustments. As of December 31, 2017, we deposited $25 million related to the acquisition, which closed on January 31, 2018.

In 2015, we acquired approximately 12,000 net acres adjacent to our existing Eagle Ford Shale acreage for approximately $111 million.

Divestitures. In December 2017, we entered into an agreement to sell certain assets in the Altamont area for approximately $180 million, subject to customary closing adjustments. As of December 31, 2017, we received a deposit of $18 million related to the divestiture, which closed in February 2018. We classified the assets and liabilities associated with the assets to be sold, including $172 million in property, plant and equipment and $2 million in asset retirement obligations, as held for sale on our consolidated balance sheet as of December 31, 2017. In 2016, we completed the sale of our assets located in the Haynesville and Bossier shales for approximately $420 million (net cash proceeds of $388 million after customary adjustments). We recorded a gain on the sale of the Haynesville/Bossier assets of approximately $79 million in 2016.

3. Impairment Charges

We evaluate capitalized costs related to proved properties upon a triggering event (such as a significant continued decline in forward commodity prices) to determine if an impairment of such properties has occurred. Capitalized costs associated with unproved properties (e.g., leasehold acquisition costs associated with non-producing areas) are also assessed upon a triggering event for impairment based on estimated drilling plans and capital expenditures, which may also change relative to forward commodity prices and/or potential lease expirations. See Notes 1 and 7 for a further discussion of our oil and natural gas properties and related significant accounting policies.

Proved Properties. During the year ended December 31, 2015, we recorded a non-cash impairment charge of approximately $4.0 billion of our proved properties in the Eagle Ford Shale reflecting a reduction in the net book value of the proved property in this area to its estimated fair value due primarily to a significant decline in estimated

forward commodity prices.
Unproved Properties. Generally, economic recovery of unproved reserves in non-producing or unproved areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by continuing exploration and development activities. Our ability to retain our leases and thus recover our non-producing leasehold costs is dependent upon a number of factors including our levels of drilling activity, which may include drilling the acreage on our own behalf or jointly

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with partners, or our ability to modify or extend our leases. Should commodity prices not justify sufficient capital allocation to the continued development of properties where we have non-producing leasehold costs, we could incur impairment charges of our unproved property costs. During the year ended December 31, 2015, we recorded a non-cash impairment charge of $288 million of our unproved properties in the Permian basin based on reduced activity and not having a definitive agreement at that time to extend our Permian lease.

In 2016, we amended our Consolidated Drilling and Development Unit Agreement with the University of Texas Land System in the Permian basin to provide flexibility to extend the time frame to hold our acreage by nearly four years to the end of 2021 (with a 10-year option beyond 2021). The agreement also increased annual well completion requirements from six wells per year to 34, 55 and 55 wells per year in 2016, 2017 and 2018, respectively. We fulfilled this requirement in 2016 and 2017.

Commodity price declines may cause changes to our capital spending levels, production rates, levels of proved reserves and development plans, which may result in an additional impairments of the carrying value of our proved and/or unproved properties in the future.

4. Income Taxes

Pretax Income (Loss) and Income Tax (Expense) Benefit. The tables below show the pretax loss and the components of income tax benefit (expense) for the following periods:

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Pretax Loss	$(203)	$(26)	$(4,326)
Components of Income Tax Benefit (Expense)			
Current			
Federal	$9	$—	$—
State	—	(1)	—
	9	(1)	—
Deferred			
Federal	$—	$—	$543
State	—	—	35
Total income tax benefit (expense)	$9	$(1)	$578

Effective Tax Rate Reconciliation. Our income taxes included in net income differ from the amount computed by applying the statutory federal income tax rate of 35% for the following reasons:

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Income taxes at the statutory federal rate of 35%	$71	$ 9	$1,514
Increase (decrease)			
State income taxes, net of federal income tax effect	(1)	1	41
Change in enacted tax rate	(409)	—	—
Change in valuation allowance	341	(9)	(975)
Other	7	(2)	(2)
Income tax benefit (expense)	$9	$ (1)	$578

The effective tax rate for the year ended December 31, 2017 was 4.5%. Our effective tax rate differed from the statutory rate of 35% primarily due to recording a current income tax benefit and related receivable for the recovery of previously paid alternative minimum taxes based on a change in our tax depreciation elections, the change in our valuation allowance on our net deferred tax assets, and non-deductible compensation expenses. Changes in our deferred taxes from year to year are offset by changes to our related valuation allowance and thus have the effect of eliminating the impact of federal taxes on our income.

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In December 2017, Congress passed into law the Tax Cuts and Jobs Act (the Act) which lowered the federal corporate tax rate from 35% to 21% effective January 1, 2018. The passage of the Act had no effect on our financial statements since the $409 million provisional effect of adjusting the tax rate on all our deferred tax balances was offset by a corresponding adjustment to the valuation allowance on our net deferred assets. While there was no overall impact on our financial statements from the Act, we are still analyzing certain aspects of the Act which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts.

The effective tax rate for the year ended December 31, 2016 was (1.9)%. Our effective tax rate differed from the statutory rate of 35% as a result of the effects of state income taxes (net of federal income tax effects), non-deductible compensation, and adjustments to the valuation allowance on our net deferred tax assets, which offset a deferred income tax benefit by $9 million.

The effective tax rate for the year ended December 31, 2015 was 13.4%, lower than the statutory rate of 35% as a result of recording a valuation allowance of $975 million against our deferred tax assets.

Deferred Tax Assets and Liabilities. The following are the components of net deferred tax assets and liabilities:

	December 31, 2017	December 31, 2016
	(in millions)	
Deferred tax assets		
Property, plant and equipment	$50	$ 249
Net operating loss carryovers	554	692
U.S. tax credit carryovers	—	10
Employee benefits	2	6
Financial derivatives	8	—
Legal and other reserves	9	6
Asset retirement obligations	8	15
Transaction costs	13	19
Total deferred tax assets	644	997
Valuation allowance	(644)	(985)
Net deferred tax assets	—	12
Deferred tax liabilities		
Financial derivatives	—	12
Total deferred tax liabilities	—	12
Net deferred tax liabilities	$—	$ —

Unrecognized Tax Benefits. As of December 31, 2017 there were no unrecognized tax benefits as income taxes in our financial statements. We did not recognize any interest and penalties related to unrecognized tax benefits (classified as income taxes in our consolidated income statements) in 2017, 2016 or 2015, nor do we have any accrued interest and penalties associated with income taxes in our consolidated balance sheets as of December 31, 2017 and December 31, 2016. The Company's and certain subsidiaries' income tax years after 2013 remain open and subject to examination by both federal and state tax authorities. During the second quarter of 2017, the Internal Revenue Service concluded an examination of our subsidiary's 2013 U.S. tax return.

Net Operating Loss and Tax Credit Carryovers. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2017 (in millions):

	Expiration Period
	2031 - 2037
U.S. federal net operating loss carryover	$ 2,522
	2026 - 2037
State net operating loss carryover	$ 411

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Utilization of $87 million of our federal net operating loss carryovers is subject to the limitations provided under Sections 382 of the Internal Revenue Code. While these limitations restrict the amount of carryovers we could potentially utilize in the next few years, it would not cause any carryovers to expire unused.
In addition to our net operating loss carryovers, we also have capital loss carryovers of $23 million, which expire in 2018 unless we are unable to generate sufficient capital gains on the sale of assets by that time. There are no alternative minimum tax credits at December 31, 2017.
Valuation Allowances. As of December 31, 2017 and 2016, we have a valuation allowance on our deferred tax assets of $644 million and $985 million, respectively. These amounts are recorded based on our evaluation of whether it was more likely than not that our deferred tax assets would be realized. Our evaluations considered cumulative book losses, the reversal of existing temporary differences, the existence of taxable income in prior carryback years, tax planning strategies and future taxable income for each of our taxable jurisdictions.

5. Earnings Per Share

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on net income per common share is antidilutive. Potentially dilutive securities consist of our stock options, restricted stock, performance share unit awards and performance unit awards. For the years ended December 31, 2017, 2016 and 2015, we incurred net losses and accordingly excluded all potentially dilutive securities from the determination of diluted earnings per share as their impact on loss per common share was antidilutive.

6. Fair Value Measurements

We use various methods to determine the fair values of our financial instruments. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. Each of the levels are described below:

- Level 1 instruments' fair values are based on quoted prices in actively traded markets.
- Level 2 instruments' fair values are based on pricing data representative of quoted prices for similar assets and liabilities in active markets (or identical assets and liabilities in less active markets).
- Level 3 instruments' fair values are partially calculated using pricing data that is similar to Level 2 instruments, but also reflect adjustments for being in less liquid markets or having longer contractual terms.

The following table presents the carrying amounts and estimated fair values of our financial instruments:

	December 31, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Short-term debt	$21	$ 19	$—	$ —
Long-term debt	$4,072	$ 3,248	$3,856	$ 3,637
Derivative instruments	$5	$ 5	$57	$ 57

For the years ended December 31, 2017 and 2016, the carrying amount of cash and cash equivalents, accounts receivable and accounts payable represent fair value because of the short-term nature of these instruments. Our long-term debt obligations (see Note 8) have various terms, and we estimated the fair value of debt (representing a Level 2 fair value measurement) primarily based on quoted market prices for the same or similar issuances, considering our credit risk.
Oil, Natural Gas and NGLs Derivative Instruments. We attempt to mitigate a portion of our commodity price risk and stabilize cash flows associated with forecasted sales of oil, natural gas and NGLs through the use of financial derivatives. As of December 31, 2017, we had derivatives contracts in the form of fixed price swaps and three-way collars on 14 MMBbls of oil in 2018. In addition to our oil derivatives, we had derivative contracts in the form of

fixed price swaps and options on 33 TBtu of natural gas (26 TBtu in 2018 and 7 TBtu in 2019) and 92 MMGal of ethane and propane fixed price swaps in 2018. As of December 31, 2016, we had derivative contracts for 16 MMBbls of oil, 36 TBtu on natural gas and 108 MMGal on ethane. In

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addition to the contracts above, we have derivative contracts related to locational basis differences on our oil and natural gas production. None of our derivative contracts are designated as accounting hedges.

As of December 31, 2017 and 2016, all derivative financial instruments were classified as Level 2. Our assessment of the level of an instrument can change over time based on the maturity or liquidity of the instrument, which can result in a change in the classification level of the financial instrument.

The following table presents the fair value associated with our derivative financial instruments as of December 31, 2017 and 2016. All of our derivative instruments are subject to master netting arrangements which provide for the unconditional right of offset for all derivative assets and liabilities with a given counterparty in the event of default. We present assets and liabilities related to these instruments in our consolidated balance sheets as either current or non-current assets or liabilities based on their anticipated settlement date, net of the impact of master netting agreements. On derivative contracts recorded as assets in the table below, we are exposed to the risk that our counterparties may not perform.

	Level 2							
	Derivative Assets				Derivative Liabilities			
	Gross		Balance Sheet Location		Gross		Balance Sheet Location	
	Fair Value	Impact of Netting	Current	Non-current	Fair Value	Impact of Netting	Current	Non-current
		(in millions)				(in millions)		
December 31, 2017								
Derivative instruments	$33	$(11)	$ 18	$ 4	$(28)	$11	$ (17)	$ —
December 31, 2016								
Derivative instruments	$79	$(17)	$ 58	$ 4	$(22)	$17	$ (4)	$ (1)

For the years ended December 31, 2017, 2016 and 2015, we recorded a derivative gain of $41 million, derivative loss of $73 million and derivative gain of $667 million, respectively. Derivative gains and losses on our oil, natural gas and NGLs financial derivative instruments are recorded in operating revenues in our consolidated income statements.

Credit Risk. We are subject to a risk of loss on our derivative instruments that could occur if our counterparties do not perform pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize our overall credit risk. These policies require that we (i) evaluate potential counterparties' financial condition to determine their credit worthiness; (ii) monitor our oil, natural gas and NGLs counterparties' credit exposures; (iii) review significant counterparties' credit from physical and financial transactions on an ongoing basis; (iv) use contractual language that affords us netting or set off opportunities to mitigate risk; and (v) when appropriate, require counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. Our assets related to derivatives as of December 31, 2017 represent financial instruments from seven counterparties, all of which are lenders associated with our $1.4 billion Reserve-based Loan facility (RBL Facility) with an "investment grade" (minimum Standard & Poor's rating of BBB- or better) credit rating. Subject to the terms of our $1.4 billion RBL Facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the RBL Facility.

Other Fair Value Considerations. During the year ended December 31, 2015, we recorded a non-cash impairment charge on our proved properties in the Eagle Ford Shale. The estimate of fair value of our proved oil and natural gas properties used to determine the impairment represented a Level 3 fair value measurement. See Notes 1 and 3 for a further discussion of our impairment charges.

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7. Property, Plant and Equipment

Oil and Natural Gas Properties. As of December 31, 2017 and 2016, we had approximately $4.4 billion and $4.5 billion, respectively, of total property, plant, and equipment, net of accumulated depreciation, depletion, and amortization on our balance sheet, substantially all of which relates to proved and unproved oil and natural gas properties.

Our capitalized costs related to proved and unproved oil and natural gas properties by area for the periods ended December 31 were as follows:

	2017	2016
	(in millions)	
Proved		
Eagle Ford	$3,219	$3,001
Permian	2,705	2,415
Altamont	1,542	1,624
Total Proved	7,466	7,040
Unproved		
Permian	66	94
Altamont	—	60
Total Unproved	66	154
Less accumulated depletion	3,137	2,731
Net capitalized costs for oil and natural gas properties	$4,395	$4,463

During 2017, we transferred approximately $63 million from unproved properties to proved properties. During 2017, 2016 and 2015, we recorded $5 million, $2 million and $9 million, respectively, of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. Suspended well costs were not material as of December 31, 2017 or December 31, 2016.

Asset Retirement Obligations. We have legal asset retirement obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We settle these obligations when production on those wells is exhausted, when we no longer plan to use them or when we abandon them. We accrue these obligations when we can estimate the timing and amount of their settlement.

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including a credit-adjusted risk-free rate between 7 and 9 percent on a significant portion of our obligations and a projected inflation rate of 2.5 percent. Changes in estimates in the table below represent changes to the expected amount and timing of payments to settle our asset retirement obligations. Typically, these changes primarily result from obtaining new information about the timing of our obligations to plug and abandon oil and natural gas wells and the costs to do so, or reassessing our assumptions in light of changing market conditions. The net asset retirement liability as of December 31 on our consolidated balance sheet in other current and non-current liabilities and the changes in the net liability for the periods ended December 31 were as follows:

	2017	2016
	(in millions)	
Net asset retirement liability at January 1	$ 41	$ 38
Liabilities settled	(2)	(1)
Accretion expense	3	3
Changes in estimate	(5)	1
Liability reclassified as held for sale	(2)	—
Net asset retirement liability at December 31	$ 35	$ 41

Capitalized Interest. Interest expense is reflected in our financial statements net of capitalized interest. We capitalize interest primarily on the costs associated with drilling and completing wells until production begins using a weighted average interest rate on our outstanding borrowings. Capitalized interest for the years ended December 31, 2017, 2016 and 2015, was approximately $4 million, $4 million and $14 million, respectively.

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8. Long Term Debt

Listed below are our debt obligations as of the periods presented:

	Interest Rate		December 31, 2017	December 31, 2016
			(in millions)	
RBL credit facility - due May 24, 2019(1)	Variable		$595	$ 370
Senior secured term loans:				
Due May 24, 2018(2)	Variable		21	21
Due April 30, 2019(3)	Variable		8	8
Due June 30, 2021(4)	Variable		—	580
Senior secured notes:				
Due November 29, 2024	8.00	%	500	500
Due February 15, 2025	8.00	%	1,000	—
Senior unsecured notes:				
Due May 1, 2020	9.375	%	1,200	1,576
Due September 1, 2022	7.75	%	250	250
Due June 15, 2023	6.375	%	519	551
Total debt			4,093	3,856
Less short-term debt, net of debt issue costs of less than $1 million			(21)	—
Total long-term debt			4,072	3,856
Less non-current portion of unamortized debt issue costs			(50)	(67)
Total long-term debt, net			$4,022	$ 3,789

(1) Carries interest at a specified margin over LIBOR of 2.50% to 3.50%, based on borrowing utilization.

(2) Issued at 99% of par and carries interest at a specified margin over the LIBOR of 2.75%, with a minimum LIBOR floor of 0.75%. As of December 31, 2017 and 2016, the effective interest rate of the term loan was 4.23% and 3.50%, respectively.

(3) Carries interest at a specified margin over the LIBOR of 3.50%, with a minimum LIBOR floor of 1.00%. As of December 31, 2017 and 2016, the effective interest rate for the term loan was 4.98% and 4.50%, respectively.

(4) As of December 31, 2016, the effective interest rate for the term loan was 9.75%.

In February 2017, we issued $1 billion of 8.00% senior secured notes which mature in 2025 and used the proceeds (less fees and expenses) to (i) repay in full our senior secured term loans due 2021, (ii) repurchase $250 million in aggregate principal amount of our 9.375% senior unsecured notes due 2020 and (iii) repay $111 million of the amounts outstanding under our RBL Facility. As a result of the issuance, our RBL Facility borrowing base was also reduced from $1.5 billion to $1.44 billion. In conjunction with these transactions, we recorded a loss on extinguishment of debt of approximately $53 million (including $30 million in non-cash expense related to eliminating associated unamortized debt issue costs and debt discounts).

In 2017 and 2016, we also repurchased additional debt as follows:

	Year ended December 31,	
	2017	2016
	(in millions)	

Debt repurchased - face value[1]	157	812
Cash paid	118	407
Gain on extinguishment of debt[2][3]	37	393

(1) In 2017, repurchases were associated with 2020 and 2023 senior unsecured notes. In 2016, repurchases were associated with certain senior unsecured notes and term loans.

(2) Includes $2 million and $12 million for the years ended December 31, 2017 and 2016, respectively, of non-cash expense related to eliminating associated unamortized debt issue costs.

(3) For the years ended December 31, 2017 and 2016, we also recorded a loss on the extinguishment of debt of approximately $1 million and $9 million, respectively, primarily related to eliminating a portion of the unamortized debt issue costs due to the reduction of our RBL Facility borrowing base in May 2016.

In January 2018, we completed an exchange of $954 million, $54 million and $139 million of the outstanding amount of our senior unsecured notes maturing in May 2020, September 2022 and June 2023, respectively, for new 9.375% senior secured notes maturing in 2024 with an aggregate principal amount of approximately $1,092 million.

Unamortized Debt Issue Costs. As of December 31, 2017 and 2016, we had total unamortized debt issue costs of $56 million and $77 million. Of these amounts $6 million and $10 million, respectively, are associated with our RBL Facility and $50 million and $67 million, respectively, are associated with our senior secured term loans and senior notes and reflected net in our debt balances. During 2017, 2016 and 2015, we amortized $14 million, $16 million and $18 million, respectively, of deferred financing costs into interest expense.

Reserve-based Loan Facility. We have a $1.4 billion RBL Facility in place which allows us to borrow funds or issue letters of credit (LC's). The facility matures in May 2019. As of December 31, 2017, we had $786 million of capacity remaining with approximately $19 million of LC's issued and approximately $595 million outstanding under the facility. Listed below is a further description of our credit facility as of December 31, 2017:

Credit Facility	Maturity Date	Interest Rate	Commitment fees
$1.4 billion RBL	May 24, 2019	LIBOR + 2.75%(1) 2.5% for LCs	0.375% commitment fee on unused capacity

(1) Based on our December 31, 2017 borrowing level. Amounts outstanding under the $1.4 billion RBL Facility bear interest at specified margins over the LIBOR of between 2.50% and 3.50% for Eurodollar loans or at specified margins over the Alternative Base Rate (ABR) of between 1.50% and 2.50% for ABR loans. Such margins will fluctuate based on the utilization of the facility.

The RBL Facility is collateralized by certain of our oil and natural gas properties and has a borrowing base subject to semi-annual redetermination. In October 2017, our RBL Facility borrowing base was affirmed at $1.4 billion. In January 2018, as a result of the debt exchange, the borrowing base was reduced from $1.4 billion to $1.36 billion. Our next redetermination date is in April 2018. Downward revisions of our oil and natural gas reserve volume and value due to declines in commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, or sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base in the future, and these reductions could be significant.

Restrictive Provisions/Covenants. The availability of borrowings under our credit agreement and our ability to incur additional indebtedness is subject to various financial and non-financial covenants and restrictions. In conjunction with the redetermination of our RBL Facility in April 2017, we extended our first lien debt to EBITDAX covenant through March 31, 2019 and the ratio was reduced to 3.0 to 1.0. As of December 31, 2017, we were in compliance with our debt covenants, with a ratio of first lien debt to EBITDAX of 0.86x. In April 2019, this financial covenant will revert to a requirement that our total net debt to EBITDAX ratio not exceed 4.5 to 1.0. As of December 31, 2017, our ratio of total net debt to EBITDAX was 5.88x. We are currently working to renew and extend the maturity of the facility as well as the required covenants thereunder.

Under our debt agreements, we are limited in non-RBL Facility debt repurchases. As of December 31, 2017, the non-RBL Facility debt repurchases limit was approximately $885 million. On January 3, 2018 we entered into a new debt agreement with the new 2024 senior secured note holders that reduced the non-RBL Facility debt repurchases limit to $225 million subject to certain customary adjustments. This limitation does not apply to debt repurchases completed using proceeds from dispositions. Certain other covenants and restrictions, among other things, also limit or place certain conditions on our ability to incur or guarantee additional indebtedness; make any restricted payments or pay any dividends on equity interests or redeem, repurchase or retire equity interests or subordinated indebtedness; sell assets; make investments; create certain liens; prepay debt obligations; engage in transactions with affiliates; and enter into certain hedge agreements.

9. Commitments and Contingencies

Legal Matters

We and our subsidiaries and affiliates are parties to various legal actions and claims that arise in the ordinary course of our business. For each matter, we evaluate the merits of the case or claim, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of our current matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. It is possible, however, that new information or future developments could require us to reassess our potential exposure and adjust our accruals accordingly, and these adjustments could be material. As of December 31, 2017, we had approximately $5 million accrued for all outstanding legal matters.

FairfieldNodal v. EP Energy E&P Company, L.P. On March 3, 2014, Fairfield filed suit against one of our subsidiaries in the 157th District Court of Harris County, Texas, claiming we were contractually obligated to pay a transfer fee

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of approximately $21 million for seismic licensing, triggered by a change in control with the Sponsors' acquisition of our predecessor entity in 2012. Prior to the change in control, we had unilaterally terminated the seismic licensing agreements, and we returned the applicable seismic data. Fairfield also claimed EP Energy did not properly maintain the confidentiality of the seismic data and interpretations made from it. In April 2015, the district court granted summary judgment to EP Energy, and Fairfield then appealed. On July 6, 2017, an intermediate court of appeals in Texas reversed the judgment related to the transfer fee and denied rehearing on October 5, 2017. We filed a petition for review in the Texas Supreme Court in December 2017. At this time, we are unable to estimate the amount or range of possible loss, if any, on this matter.

Indemnifications and Other Matters. We periodically enter into indemnification arrangements as part of the divestiture of assets or businesses. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, environmental and other contingent matters. In addition, under various laws or regulations, we could be subject to the imposition of certain liabilities. For example, the decline in commodity prices has created an environment where there is an increased risk that owners and/or operators of assets previously purchased from us may no longer be able to satisfy plugging and abandonment obligations that attach to such assets. In that event, under various laws or regulations, we could be required to assume all, or a portion of the plugging or abandonment obligations on assets we no longer own or operate. As of December 31, 2017, we had approximately $5 million accrued related to these indemnifications and other matters.

Non-Income Tax Matters. We are under a number of examinations by taxing authorities related to non-income tax matters. As of December 31, 2017, we had approximately $42 million accrued (in other accrued liabilities in our consolidated balance sheet) in connection with ongoing examinations related to certain prior period non-income tax matters.

Environmental Matters

We are subject to existing federal, state and local laws and regulations governing environmental quality, pollution control and greenhouse gas (GHG) emissions. Numerous governmental agencies, such as the Environmental Protection Agency (EPA), issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. Our management believes that we are in substantial compliance with applicable environmental laws and regulations, and we have not experienced any material adverse effect from compliance with these environmental requirements. For additional details on certain environmental matters related to climate change, air quality and other emissions, hydraulic fracturing regulations and waste handling, refer to Part I, Item 1A, "Risk Factors".

While our reserves for environmental matters are currently not material, there are still uncertainties related to the ultimate costs we may incur in the future in order to comply with increasingly strict environmental laws, regulations, and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons resulting from our current or past operations. Based upon our evaluation and experience to date, however, we believe our accruals for these matters are adequate. It is possible that new information or future developments could result in substantial additional costs and liabilities which could require us to reassess our potential exposure related to these matters and to adjust our accruals accordingly, and these adjustments could be material.

Lease Obligations

We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and various equipment. The terms of the agreements, the largest of which relates to our building lease, vary through 2025. Future minimum annual rental commitments under non-cancelable future operating lease commitments at December 31, 2017, were as follows:

Year Ending December 31,	Operating Leases (in millions)
2018	$ 5
2019	5
2020	5

2021	5	
Thereafter	22	
Total	$	42

Rental expense for the years ended December 31, 2017, 2016 and 2015 was $6 million, $13 million and $12 million, respectively.

Other Commercial Commitments

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At December 31, 2017, we have various commercial commitments totaling $336 million primarily related to commitments and contracts associated with volume and transportation, completion activities and seismic activities. Our annual obligations under these arrangements are $103 million in 2018, $76 million in 2019, $58 million in 2020, $52 million in 2021, and $47 million thereafter.

10. Long-Term Incentive Compensation / 401(k) Retirement Plan

Overview. Under our current stock-based compensation plans (the EP Energy Corporation 2014 Omnibus Incentive Plan and 2017 EP Energy Corporation Employment Inducement Plan), we may issue to our employees and non-employee directors various forms of long-term incentive (LTI) compensation including stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares/units, incentive awards, cash awards, and other stock-based awards. We are authorized to grant awards of up to 36,832,525 shares of our common stock for awards under these plans, with 28,695,370 shares remaining available for issuance as of December 31, 2017.

In addition, in conjunction with the acquisition of certain of our subsidiaries by Apollo and other private equity investors in 2012 (the Acquisition), we issued Class B shares (formerly management incentive units intended to constitute profits interests) which become payable should certain liquidity events occur. No additional Class B shares are available for issuance.

We record stock-based compensation expense as general and administrative expense over the requisite service period. For the years ended December 31, 2017, 2016 and 2015, we recognized pre-tax compensation expense related to our LTI programs, net of the impact of forfeitures of approximately $(19) million, $22 million and $21 million, respectively, and recorded an associated income tax benefit of $5 million, $9 million and $6 million for the years 2017, 2016 and 2015, respectively. As a result of a change in our management and certain other staff reductions and departures during 2017, we recorded a reduction of compensation expense of approximately $33 million related to the reversal of previously recognized compensation expense to reflect the forfeitures of these individual's LTI awards.

Restricted stock. We grant shares of restricted common stock which carry voting and dividend rights and may not be sold or transferred until they are vested. The fair value of our restricted stock is determined on the date of grant and these shares generally vest in equal amounts over 3 years from the date of the grant. A summary of the changes in our non-vested restricted shares for the year ended December 31, 2017 is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value per Share
Non-vested at December 31, 2016	6,326,788	$ 7.69
Granted	5,895,639	$ 3.92
Vested	(2,355,507)	$ 8.42
Forfeited	(4,582,934)	$ 5.86
Non-vested at December 31, 2017	5,283,986	$ 4.63

The total unrecognized compensation cost related to these arrangements at December 31, 2017 was approximately $17 million, which is expected to be recognized over a weighted average period of 2 years.

Stock Options. In 2014, we granted stock options as compensation for future service at an exercise price equal to the closing share price of our stock on the grant date. No stock options were granted subsequent to 2014. Stock options granted have contractual terms of 10 years and vest in three tranches over a five-year period (with the first tranche vesting on the third anniversary of the grant date, the second tranche vesting on the fourth anniversary of the grant date and the third tranche vesting on the fifth anniversary thereof). We do not pay dividends on unexercised options. As of December 31, 2017 we had approximately 101,844 outstanding options with a weighted average exercise price of $19.82 per share and a weighted average remaining contractual term of 6.25 years. There were no options exercised during the year, and options outstanding had no intrinsic value as of December 31, 2017. Total compensation cost related to non-vested option awards not yet recognized at December 31, 2017 was less than $1 million, which is expected to be recognized over a weighted average period of 1 year.

Class B Shares. At the time of the Acquisition in 2012, certain employees were awarded management incentive units (MIPs) intended to constitute profits interests. In 2013, these MIPs converted into Class B shares on a one-for-one basis. Any payout on Class B shares occurs based on the achievement of certain predetermined performance measures (e.g., certain liquidity events in which our private equity investors receive a return of at least one times their invested capital plus a stated return). The MIPs were issued at no cost to the employees and have value only to the extent the value of the Company increases. For accounting purposes, these awards were treated as compensatory equity awards at the date of grant. As of

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December 31, 2017, we had unrecognized compensation expense of $3 million, which will only be recognized should the certain liquidity events described above occur and the right to such amounts become nonforfeitable.

Performance Share Units. In November 2017, we granted 912,000 performance share units (PSUs) to certain members of EP Energy's management team. The PSUs represent a contractual right to receive one share of EP Energy’s common stock if certain conditions are met, and the number of PSUs actually earned, if any, will be based upon achievement of specified stock price goals over a four-year performance period (grant date thru October 2021). The PSUs vest over a six-year period; 80% ratably over the first four years and the final 20% on the sixth year with settlement dates over three years; 20% in the fourth year, 20% in the fifth year and 60% in the sixth year. The PSUs will settle in shares of common stock if certain stock price hurdles are met, but such shares will remain subject to transfer restrictions through October 2024 unless certain conditions are satisfied.

For accounting purposes, the PSUs are treated as an equity award with the expense recognized on an accelerated basis over the life of the award. The grant date fair value of these awards was approximately $12 million as determined by a Monte Carlo simulation utilizing multiple input variables that determine the probability of satisfying the market condition stipulated in the award. We estimated an expected volatility of approximately 86.77% based on life-to-date volatility of EP Energy’s common stock, which has been publicly traded for an amount of time less than the contractual term of the award. We estimated a risk free rate of 2.10% based on the yield, as of the valuation date, on zero coupon U.S. Treasury STRIPS (Separate Trading of Registered Interest and Principal of Securities) that have a term equal to the length of the period from the valuation date to the final vest date. The expected term of the award is 6 years. Total compensation cost related to our non-vested performance share units not yet recognized at December 31, 2017 was $11 million, which is expected to be recognized over a weighted average period of 3 years.

Performance Unit Awards. We granted performance unit awards to certain members of EP Energy's management team. Performance units have a target value of $100 per unit; however, the ultimate value of each performance unit will range from zero to $200 depending on the level of total shareholder return (TSR) relative to that of EP Energy’s peer group of companies for the performance period. Performance units awarded in 2016 are subject to three separate performance periods starting on January 1, 2016 and ending on December 31, 2016, 2017 and 2018 and vest in three separate tranches over the requisite service period beginning on the grant date. Performance units awarded in 2017 are subject to one performance period starting on January 1, 2017 and ending on December 31, 2019 and "cliff" vest three years from the grant date. The awards may be settled in either stock or cash at the election of the Board of Directors. Had all performance unit awards vested on December 31, 2017 and been settled in stock, no shares would have been issued.

For accounting purposes, the performance unit awards are treated as a liability award with the expense recognized on an accelerated basis over the life of the award and fair value remeasured at each reporting period. As of December 31, 2017 and 2016, we had approximately 18,317 and 78,900 awards outstanding, respectively. The fair value of these awards measured as of December 31, 2017 was less than $1 million for both the 2017 and 2016 awards determined using a Monte Carlo simulation. The following table summarizes the significant assumptions used to calculate the fair value of the performance unit awards as of December 31, 2017, which were granted in 2016 and 2017:

	2016 Awards	2017 Awards
Expected Term in Years	3.0	3.0
Expected Volatility(1)	64.93 %	100.03 %
Expected Dividends	—	—
Risk-Free Interest Rate(2)	1.76 %	1.89 %

(1) Expected volatility assumption for performance unit awards is based on the historical stock price volatility equal to the remaining length of the performance period as of the valuation date.

(2) The risk-free rate is based upon the yield on U.S. Treasury STRIPS over the expected term as of the grant date.

Total compensation cost related to our non-vested performance unit awards not yet recognized at December 31, 2017 was less than $1 million, which is expected to be recognized over a weighted average period of 2 years.

Other. In September 2013, we issued an additional 70,000 shares of Class B common stock to EPE Employee Holdings II, LLC (EPE Holdings II), a subsidiary. EPE Holdings II was formed to hold such shares and serve as an entity through which current and future employee incentive awards would be granted. Holders of the awards do not hold actual Class B common stock or equity in EPE Holdings II, but rather will have a right to receive proceeds paid to EPE Holdings II in respect of such shares which is conditional upon certain events (e.g., certain liquidity events in which our private equity

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investors receive a return of at least one times their invested capital plus a stated return) that are not yet probable of occurring. As a result, no compensation expense was recognized upon the issuance of the Class B shares to EPE Holdings II, and none will occur until those events that give rise to a payout on such shares becomes probable of occurring. At that time, the full value of the awards issued to EPE Holdings II will be recognized based on actual amounts paid, if any, on the Class B common stock.

401(k) Retirement Plan. We sponsor a tax-qualified defined contribution retirement plan for a broad-based group of employees. We make matching contributions (dollar for dollar up to 6% of eligible compensation) and non-elective employer contributions (5% of eligible compensation) to the plan, and individual employees are also eligible to contribute to the defined contribution plan. During 2017, 2016 and 2015, we contributed $7 million, $9 million and $10 million, respectively, of matching and non-elective employer contributions.

11. Related Party Transactions

Affiliate Payments. In November 2017, in connection with the release of members of the leadership team of a portfolio company of funds managed by Apollo Management, LLC (Apollo) affiliates to join the Company, the Company reimbursed that portfolio company approximately $4 million for money contributed to it by fund investors (other than Apollo).

Joint Venture. In January 2017, we entered into a drilling joint venture with Wolfcamp Drillco Operating L.P. (the Investor), which is managed and controlled by an affiliate of Apollo Global Management LLC, to fund future oil and natural gas development in the Permian basin. Subsequently, Access Industries acquired an indirect minority ownership interest in the Investor, and therefore is also indirectly responsible for funding a portion of the Investor’s capital commitment. The Investor may fund approximately $450 million over the entire program (150 wells in two separate 75 well tranches), or approximately 60 percent of the estimated drilling, completion and equipping costs of the wells, in exchange for a 50 percent working interest in the joint venture wells. Once the Investor achieves a 12 percent internal rate of return on its invested capital in each tranche, its working interest will revert to 15 percent. We are the operator of the joint venture assets. The first wells under the joint venture began producing in January 2017, and for the year ended December 31, 2017, we recovered approximately $214 million related to the capital costs of the joint venture wells from the Investor and have drilled and completed 58 wells.

Affiliate Supply Agreement. For the years ended December 31, 2017, 2016 and 2015, we recorded approximately $1 million, $6 million and $67 million, respectively, in capital expenditures for amounts expended under supply agreements entered into with an affiliate of Apollo to provide certain fracturing materials used in our Eagle Ford drilling operations.

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Supplemental Selected Quarterly Financial Information (Unaudited)
Financial information by quarter is summarized below (in millions, except per common share amounts).

2017	March 31	June 30	September 30	December 31
Operating revenues				
Physical sales	$ 257	$ 251	$ 242	$ 275
Financial derivatives	70	45	(23)	(51)
Operating income (loss)	89	61	(18)	7
Income tax benefit	—	5	2	2
Net loss	$ (47)	$ (3)	$ (72)	$ (72)
Basic and diluted net loss per common share				
Net loss	$ (0.19)	$ (0.01)	$ (0.29)	$ (0.29)

2016	March 31	June 30	September 30	December 31
Operating revenues				
Physical sales	$ 182	$ 205	$ 212	$ 241
Financial derivatives	42	(105)	43	(53)
Operating (loss) income	(18)	(27)	6	(59)
Income tax expense	—	—	(1)	—
Net income (loss)	$ 94	$ 62	$ (43)	$ (140)
Basic and diluted net income (loss) per common share				
Net income (loss)	$ 0.38	$ 0.25	$ (0.18)	$ (0.57)

Below are additional significant items affecting comparability of amounts reported in the respective periods of 2017 and 2016:
September 30, 2017. We recorded a $24 million gain on extinguishment of debt in conjunction with repurchasing a portion of our senior unsecured notes.
June 30, 2017. We recorded a $13 million gain on extinguishment of debt in conjunction with repurchasing a portion of our senior unsecured notes.
March 31, 2017. We recorded a $53 million loss on extinguishment of debt in conjunction with issuing $1 billion of 8.00% senior secured notes.
September 30, 2016. We recorded a $26 million gain on extinguishment of debt in conjunction with repurchasing a portion of our senior unsecured notes and term loans.
June 30, 2016. We recorded a $162 million gain on extinguishment of debt primarily in conjunction with repurchasing a portion of our senior unsecured notes and term loans. In addition, we recorded an $83 million gain on sale of assets related to the sale of our assets in the Haynesville and Bossier shales.
March 31, 2016. We recorded a $196 million gain on extinguishment of debt in conjunction with repurchasing a portion of our senior unsecured notes.

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Supplemental Oil and Natural Gas Operations (Unaudited)

We are engaged in the exploration for, and the acquisition, development and production of oil, natural gas and NGLs, in the United States (U.S.).

Capitalized Costs. Capitalized costs relating to domestic oil and natural gas producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31 (in millions):

	2017[(1)]	2016
Oil and natural gas properties	$7,532	$7,194
Less accumulated depreciation, depletion and amortization	3,137	2,731
Net capitalized costs	$4,395	$4,463

(1) December 31, 2017 does not include amounts related to certain assets in the Altamont area as these capitalized costs are reflected as assets held for sale on our consolidated balance sheet.

Total Costs Incurred. Costs incurred in oil and natural gas producing activities, whether capitalized or expensed, were as follows for the years ended December 31, 2017, 2016 and 2015 (in millions):

	U.S.
2017 Consolidated:	
Property acquisition costs	
Proved properties	$7
Unproved properties[(1)]	27
Exploration costs (capitalized and expensed)	6
Development costs	544
Costs expended	584
Asset retirement obligation costs	—
Total costs incurred	$584
2016 Consolidated:	
Property acquisition costs	
Unproved properties	$8
Exploration costs (capitalized and expensed)	4
Development costs	472
Costs expended	484
Asset retirement obligation costs	—
Total costs incurred	$484
2015 Consolidated:	
Property acquisition costs	
Proved properties	$111
Unproved properties	12
Exploration costs (capitalized and expensed)	26
Development costs	1,168
Costs expended	1,317
Asset retirement obligation costs	4
Total costs incurred	$1,321

(1) Includes approximately $5 million related to lease extensions and renewals.

We capitalize salaries and benefits that we determine are directly attributable to our oil and natural gas activities. The table above includes capitalized labor costs of $23 million, $27 million and $31 million for the years ended

December 31, 2017, 2016 and 2015, and capitalized interest of $4 million, $4 million and $14 million for the same periods.

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Oil and Natural Gas Reserves. Net quantities of proved developed and undeveloped reserves of natural gas, oil and NGLs and changes in these reserves at December 31, 2017 presented in the tables below are based on our internal reserve report. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate. Our 2017 proved reserves were consistent with estimates of proved reserves filed with other federal agencies in 2017 except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience.

Ryder Scott Company, L.P. (Ryder Scott), conducted an audit of the estimates of the proved reserves that we prepared as of December 31, 2017. In connection with its audit, Ryder Scott reviewed 100% (by volume) of our total proved reserves on a barrel of oil equivalent basis, representing 99% of the total discounted future net cash flows of these proved reserves. Ryder Scott did not audit our non-operated properties, which are less than 1% of our net proved reserves by volume. For the audited properties, 100% of our total proved undeveloped (PUD) reserves were evaluated. Ryder Scott concluded the overall procedures and methodologies that we utilized in preparing our estimates of proved reserves as of December 31, 2017 complied with current SEC regulations and the overall proved reserves for the reviewed properties as estimated by us are, in aggregate, reasonable within the established audit tolerance guidelines of 10% as set forth in the Society of Petroleum Engineers auditing standards. Ryder Scott's report is included as an exhibit to this Annual Report on Form 10-K.

	Year Ended December 31, 2017[(1)]			
	Natural Gas (in Bcf)	Oil (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)
Proved developed and undeveloped reserves				
Beginning of year	732	219,783	90,575	432.4
Revisions due to prices	16	5,937	1,733	10.4
Revisions other than prices[(2)]	(72)	(3,369)	(11,950)	(27.3)
Extensions and discoveries[(3)]	44	10,143	6,752	24.2
Purchase of reserves	—	102	16	0.1
Sales of reserves in place	(22)	(11,898)	(2,183)	(17.7)
Production	(46)	(16,833)	(5,466)	(30.0)
End of year	652	203,865	79,477	392.1
Proved developed reserves:				
Beginning of year	346	108,133	38,887	204.6
End of year	372	114,282	41,989	218.3
Proved undeveloped reserves:				
Beginning of year	386	111,649	51,689	227.8
End of year	280	89,584	37,489	173.8

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $51.34 per Bbl (WTI) and $2.98 per MMBtu (Henry Hub).

(2) The 27 MMBoe of revisions other than prices includes 23 MMBoe of negative PUD revisions due to a reallocation of capital in our development areas and 4 MMBoe of negative revisions. The negative 4 MMBoe of revisions includes a negative revision of 13 MMBoe in the Permian, a net positive revision of 6 MMBoe in Eagle Ford and a net positive revision of 3 MMBoe in Altamont.

(3) The 24 MMBoe of extensions and discoveries are all in the Permian. Of the 24 MMBoe of extensions and discoveries, 16 MMBoe were liquids representing 70% of EP Energy's total extensions and discoveries.

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	Year Ended December 31, 2016[1]			
	Natural Gas (in Bcf)	Oil (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)
Proved developed and undeveloped reserves				
Beginning of year	938	298,741	90,875	546.0
Revisions due to prices	(22)	(10,434)	(3,770)	(17.9)
Revisions other than prices[2]	(52)	(75,462)	(8,293)	(92.4)
Extensions and discoveries[3]	129	25,492	17,146	64.1
Sales of reserves in place	(203)	(1,493)	—	(35.3)
Production	(58)	(17,061)	(5,383)	(32.1)
End of year	732	219,783	90,575	432.4
Proved developed reserves:				
Beginning of year	530	131,804	36,442	256.6
End of year	346	108,133	38,887	204.6
Proved undeveloped reserves:				
Beginning of year	408	166,937	54,432	289.4
End of year	386	111,649	51,689	227.8

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $42.75 per Bbl (WTI) and $2.48 per MMBtu (Henry Hub).

(2) The 92 MMBoe of revisions other than prices includes 98 MMBoe of negative PUD revisions due to reductions in our estimated capital in our five-year development plan and 6 MMBoe of positive revisions. The positive 6 MMBoe of revisions includes a net positive revision of 35 MMBoe in Permian, a net positive revision of 3 MMBoe in Altamont, a net positive revision of 1 MMBoe in non-core assets and a negative revision of 33 MMBoe in Eagle Ford.

(3) Of the 64 MMBoe of extensions and discoveries, 55 MMBoe are in the Permian, 8 MMBoe are in the Altamont area and 1 MMBoe are in the Eagle Ford Shale. Of the 64 MMBoe of extensions and discoveries, 43 MMBoe were liquids representing 66% of EP Energy’s total extensions and discoveries.

	Year Ended December 31, 2015[1]			
	Natural Gas (in Bcf)	Oil (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)
Proved developed and undeveloped reserves				
Beginning of year	1,243	320,813	94,226	622.2
Revisions due to prices	(44)	(16,288)	(3,880)	(27.5)
Revisions other than prices[2]	(294)	(32,778)	(6,422)	(88.2)
Extensions and discoveries[3]	100	41,189	11,065	68.9
Purchase of reserves	9	7,883	1,252	10.6
Production	(76)	(22,078)	(5,366)	(40.0)
End of year	938	298,741	90,875	546.0
Proved developed reserves:				
Beginning of year	464	128,396	32,474	238.1
End of year	530	131,804	36,442	256.6
Proved undeveloped reserves:				
Beginning of year	779	192,417	61,752	384.1

End of year	408	166,937	54,432	289.4

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $50.28 per Bbl (WTI) and $2.59 per MMBtu (Henry Hub).

(2) Of the 88 MMBoe of revisions other than prices, 85 MMBoe were negative PUD revisions due to the impact of reductions in estimated capital in our long-range development plan based on the lower price environment.

(3) Of the 69 MMBoe of extensions and discoveries, 18 MMBoe are in the Eagle Ford Shale, 32 MMBoe are in the Permian, 19 MMBoe are in the Altamont area and less than 1 MMBoe are in the Haynesville Shale. Of the 69 MMBoe of extensions and discoveries, 52 MMBoe were liquids representing 76% of EP Energy's total extensions and discoveries.

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In accordance with SEC Regulation S-X, Rule 4-10 as amended, we use the 12-month average price calculated as the unweighted arithmetic average of the spot price on the first day of each month preceding the 12-month period prior to the end of the reporting period. The first day 12-month average price used to estimate our proved reserves at December 31, 2017 was $51.34 per barrel of oil (WTI) and $2.98 per MMBtu for natural gas (Henry Hub).

All estimates of proved reserves are determined according to the rules prescribed by the SEC in existence at the time estimates were made. These rules require that the standard of “reasonable certainty” be applied to proved reserve estimates, which is defined as having a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as more technical and economic data becomes available, a positive or upward revision or no revision is much more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including many factors beyond our control such as reservoir performance, prices, economic conditions and government restrictions. In addition, as a result of drilling, testing and production subsequent to the date of an estimate; a revision of that estimate may be necessary. Reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Estimating quantities of proved oil and natural gas reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which they are based upon economic factors, such as oil and natural gas prices, production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effects of governmental regulation. In addition, due to the lack of substantial, if any, production data, there are greater uncertainties in estimating proved undeveloped reserves, proved developed non-producing reserves and proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise.

The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from oil and natural gas properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Subsequent to December 31, 2017, there have been no major discoveries, favorable or otherwise, on our proved reserves volumes that may be considered to have caused a significant change in our estimated proved reserves at December 31, 2017.

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Results of Operations. Results of operations for oil and natural gas producing activities for the years ended December 31, 2017, 2016 and 2015 (in millions):

	U.S.
2017 Consolidated:	
Net Revenues[1] — Sales to external customers	$1,025
Costs of products and services	(131)
Production costs[2]	(223)
Depreciation, depletion and amortization[3]	(476)
Exploration and other expense	(12)
	183
Income tax expense	(66)
Results of operations from producing activities	$117
2016 Consolidated:	
Net Revenues[1] — Sales to external customers	$840
Costs of products and services	(136)
Production costs[2]	(203)
Depreciation, depletion and amortization[3]	(450)
Exploration and other expense	(5)
	46
Income tax expense	(17)
Results of operations from producing activities	$29
2015 Consolidated:	
Net Revenues[1] — Sales to external customers	$1,241
Costs of products and services	(169)
Production costs[2]	(259)
Impairment charges	(4,297)
Depreciation, depletion and amortization[3]	(971)
Exploration and other expense	(20)
	(4,475)
Income tax benefit	1,607
Results of operations from producing activities	$(2,868)

(1) Excludes the effects of oil and natural gas derivative contracts.
(2) Production costs include lease operating expense and production related taxes, including ad valorem and severance taxes.
(3) Includes accretion expense on asset retirement obligations of $3 million for each of the years ended December 31, 2017, 2016 and 2015.

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Standardized Measure of Discounted Future Net Cash Flows. The standardized measure of discounted future net cash flows relating to our consolidated proved oil and natural gas reserves at December 31 is as follows (in millions):

	U.S.
2017 Consolidated:	
Future cash inflows[1]	$12,395
Future production costs	(5,363)
Future development costs	(2,692)
Future income tax expenses	(149)
Future net cash flows	4,191
10% annual discount for estimated timing of cash flows	(2,158)
Standardized measure of discounted future net cash flows	$2,033
2016 Consolidated:	
Future cash inflows[1]	$10,507
Future production costs	(5,061)
Future development costs	(2,824)
Future income tax expenses	(140)
Future net cash flows	2,482
10% annual discount for estimated timing of cash flows	(1,455)
Standardized measure of discounted future net cash flows	$1,027
2015 Consolidated:	
Future cash inflows[1]	$16,416
Future production costs	(6,903)
Future development costs	(4,668)
Future income tax expenses	(280)
Future net cash flows	4,565
10% annual discount for estimated timing of cash flows	(2,581)
Standardized measure of discounted future net cash flows	$1,984

(1) The company had no commodity-based derivative contracts designated as accounting hedges at December 31, 2017, 2016 and 2015. Amounts also exclude the impact on future net cash flows of derivatives not designated as accounting hedges.

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Changes in Standardized Measure of Discounted Future Net Cash Flows. The following are the principal sources of change in our consolidated standardized measure of discounted future net cash flows (in millions):

	Year Ended December 31,[1]		
	2017	2016	2015
Consolidated:			
Sales and transfers of oil and natural gas produced net of production costs	$(801)	$(637)	$(982)
Net changes in prices and production costs	1,048	(1,068)	(7,085)
Extensions, discoveries and improved recovery, less related costs	98	57	145
Changes in estimated future development costs	(196)	1,267	997
Previously estimated development costs incurred during the period	441	281	835
Revision of previous quantity estimates	(181)	(812)	(1,008)
Accretion of discount	157	281	954
Net change in income taxes	(1)	24	2,428
Purchase of reserves in place	1	—	48
Sales of reserves in place	(48)	(75)	—
Change in production rates, timing and other	488	(275)	(1,246)
Net change	$1,006	$(957)	$(4,914)
Representative NYMEX prices:[2]			
Oil (Bbl)	$51.34	$42.75	$50.28
Natural gas (MMBtu)	$2.98	$2.48	$2.59

(1) This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.

(2) Average first day of the month spot price for the preceding 12-month period before price differentials and deducts. Price differentials and deducts were applied when the estimated future cash flows from estimated production from proved reserves were calculated.

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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

As of December 31, 2017, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of December 31, 2017. See Part II, Item 8, “Financial Statements and Supplementary Data” under Management’s Annual Report on Internal Control Over Financial Reporting.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2017 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Stockholders.

Item 11. Executive Compensation

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Stockholders.

Item 13. Certain Relationships and Related Transactions and Director Independence

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Stockholders.

Item 14. Principal Accountant Fees and Services

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Stockholders.

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PART IV
ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES
(a) The following documents are filed as a part of this report:
1. Financial statements: Refer to Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.
2. Financial statement schedules: Refer to Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.

3. and (b). Exhibits
The exhibits identified below are filed as part of this report and are hereby incorporated herein by reference. The list below is a list of those exhibits filed herewith, and includes and identifies management contracts or compensatory plans or arrangements required to be filed as exhibits to this Annual Report on Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.
The agreements included as exhibits to this report are intended to provide information regarding their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements may contain representations and warranties by the parties to the agreements, including us, solely for the benefit of the other parties to the applicable agreements and:
•should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
•may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
•may apply standards of materiality in a way that is different from what may be viewed as material to certain investors; and
•were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments. Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.
Exhibits filed with this report are designated by “*”. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a “+” constitute a management contract or compensatory plan or arrangement. Exhibits designated with a “†” indicate that a confidential treatment has been granted with respect to certain portions of the exhibit. Omitted portions have been filed separately with the SEC. Exhibits designated with a "#" have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A list of these exhibits and schedules is included after the table of contents in the Participation and Development Agreement. The Company agrees to furnish a supplemental copy of any such omitted exhibit or schedule to the SEC upon request.

Exhibit No.	Exhibit Description
2.1	Purchase and Sale Agreement among EP Energy Corporation, EP Energy Holding Company and El Paso Brazil, L.L.C., as sellers, and EPE Acquisition, LLC, as purchaser, dated as of February 24, 2012 (Exhibit 2.1 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
2.2	Amendment No. 1 to Purchase and Sale Agreement, dated as of April 16, 2012, among EP Energy, L.L.C. (f/k/a EP Energy Corporation), EP Energy Holding Company, El Paso Brazil, L.L.C. and EPE Acquisition, LLC (Exhibit 2.2 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
2.3	Amendment No. 2 to Purchase and Sale Agreement, dated as of May 24, 2012, among EP Energy, L.L.C. (f/k/a EP Energy Corporation), EP Energy Holding Company, El Paso Brazil, L.L.C., EP Production International Cayman Company, EPE Acquisition, LLC and solely for purposes of Sections 2 and 5 thereunder, El Paso LLC (Exhibit 2.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
2.4	Purchase and Sale Agreement, dated as of June 9, 2013, by and among EP Energy E&P Company, L.P., EPE Nominee Corp. and Atlas Resource Partners, L.P. (Exhibit 2.1 to EP Energy LLC's Current Report on Form 8-K, filed with the SEC on June 13, 2013).
2.5	Purchase and Sale Agreement, dated as of March 18, 2016, by and among EP Energy E&P Company, L.P., EP Energy Management, L.L.C., and Crystal E&P Company, L.L.C., as Seller and Covey Park Gas LLC (Exhibit2.1 to Company's Current Report on Form 8-K, filed with the SEC on May 4, 2016).
#2.6	Participation and Development Agreement, dated as of January 24, 2017, by and among EP Energy E&P Company, L.P. and Wolfcamp DrillCo Operating L.P. (Exhibit 2.5 to Company's Annual Report on Form 10-K filed with the SEC on March 3, 2017).
2.7	Letter Agreement, dated as of January 24, 2017, by and among EP Energy E&P Company, L.P. and Wolfcamp DrillCo Operating L.P. (Exhibit 2.6 to Company's Annual Report on Form 10-K filed with the SEC on March 3, 2017).
3.1	Second Amended and Restated Certificate of Incorporation of EP Energy Corporation (Exhibit 3.1 to Company's Current Report on Form 8-K, filed with the SEC on January 23, 2014).
3.2	

	Amended and Restated Bylaws of EP Energy Corporation (Exhibit 3.2 to Company's Current Report on Form 8-K, filed with the SEC on January 23, 2014).
4.1	Indenture, dated as of April 24, 2012, between EP Energy LLC (f/k/a Everest Acquisition LLC) and Everest Acquisition Finance Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 9.375% Senior Notes due 2020 (Exhibit 4.2 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.2	Indenture, dated as of August 13, 2012, between EP Energy LLC and Everest Acquisition Finance Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 7.750% Senior Notes due 2022 (Exhibit 4.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.3	Indenture, dated as of May 28, 2015, between EP Energy LLC and Everest Acquisition Finance Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 6.375% Senior Notes due 2023 (Exhibit 4.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on June 24, 2015).
4.4	Indenture, dated as of November 29, 2016, by and among EP Energy LLC, Everest Acquisition Finance Inc., the Guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent (Exhibit 4.1 to Company's Current Report on Form 8-K, filed with the SEC on November 30, 2016).
4.5	Indenture, dated as of February 6, 2017, by and among EP Energy LLC, Everest Acquisition Finance Inc., the Guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent (Exhibit 4.1 to Company's Current Report on Form 8-K, filed with the SEC on February 7, 2017).
4.6	Indenture, dated as of January 3, 2018, by and among EP Energy LLC, Everest Acquisition Finance Inc., the Subsidiary Guarantors thereto and Wilmington Trust, National Association, as trustee and collateral agent (Exhibit 4.1 to Company's Current Report on Form 8-K, filed with the SEC on December 22, 2017).
4.7	Second Supplemental Indenture, dated as of December 21, 2017, by and among EP Energy LLC, Everest Acquisition Finance Inc. and Wilmington Trust, National Association, as trustee (Exhibit 4.1 to EP Energy LLC's Current Report on Form 8-K, filed with the SEC on January 4, 2018).
4.8	Registration Rights Agreement, dated as of May 28, 2015, between EP Energy LLC, Everest Acquisition Finance Inc. and RBC Capital Markets, LLC, as representative of the several initial purchasers, in respect of 6.375% Senior Notes due 2023 (Exhibit 4.5 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on June 24, 2015).

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Exhibit No.	Exhibit Description
4.9	Registration Rights Agreement, dated as of April 24, 2012, between EP Energy LLC (f/k/a Everest Acquisition LLC), Everest Acquisition Finance Inc. and Citigroup Global Markets Inc. and J.P. Morgan Securities LLC, as representatives of the several initial purchasers, in respect of 9.375% Senior Notes due 2020 (Exhibit 4.5 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.10	Registration Rights Agreement, dated as of August 13, 2012, between EP Energy LLC, Everest Acquisition Finance Inc. and Citigroup Global Markets Inc., as representative of the several initial purchasers, in respect of 7.750% Senior Notes due 2022 (Exhibit 4.6 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.11	Registration Rights Agreement, dated as of August 30, 2013, between EP Energy Corporation and the stockholders party thereto (Exhibit 4.8 to the Company's Registration Statement on Form S-1, filed with the SEC on September 4, 2013).
10.1	Credit Agreement, dated as of May 24, 2012, by and among EPE Holdings, LLC, as Holdings, EP Energy LLC (f/k/a Everest Acquisition LLC), as the Borrower, the Lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent and Collateral Agent, and the other parties party thereto (Exhibit 10.1 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.2	Guarantee Agreement, dated as of May 24, 2012, by and among EPE Holdings LLC, the Domestic Subsidiaries of the Borrower signatory thereto and JPMorgan Chase Bank, N.A., as collateral agent for the Secured Parties referred to therein (Exhibit 10.2 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.3	Collateral Agreement, dated as of May 24, 2012, by and among EPE Holdings LLC, EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.4	Pledge Agreement, dated as of May 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.4 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.5	Pledge Agreement, dated as of May 24, 2012, by and among El Paso Brazil, L.L.C., as Pledgor, and JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.5 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).

10.6	Amendment, dated as of August 17, 2012, to the Credit Agreement, dated as of May 24, 2012, among EPE Holdings LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.15 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.7	Second Amendment, dated as of March 27, 2013, to the Credit Agreement, dated as of May 24, 2012, among EPE Holdings LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to EP Energy LLC's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2013, filed with the SEC on May 9, 2013).
10.8	Third Amendment, dated as of October 27, 2014, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2013, filed with the SEC on April 30, 2015).
10.9	Fourth Amendment, dated as of April 6, 2015, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on April 7, 2015).
10.10	Fifth Amendment, dated as of May 2, 2016, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on May 4, 2016).
10.11	Sixth Amendment, dated as of November 11, 2016, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017, filed with the SEC on August 3, 2017).
10.12	Seventh Amendment, dated as of April 24, 2017, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.2 to Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017, filed with the SEC on August 3, 2017).

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Exhibit No.	Exhibit Description
10.13	Consent and Agreement to Credit Agreement, dated as of June 7, 2013, among EPE Holdings LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.3 to EP Energy LLC's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2013, filed with the SEC on August 14, 2013).
10.14	Assumption and Ratification Agreement, dated as of April 30, 2014, entered into by EPE Acquisition, LLC, in favor of the Secured Parties (as defined in the Credit Agreement) (Exhibit 10.9 to Company's Annual Report on Form 10-K, filed with the SEC on February 23, 2015).
10.15	Senior Lien Intercreditor Agreement, dated as of May 24, 2012, among JPMorgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Citibank, N.A., as Term Facility Agent, Senior Secured Notes Collateral Agent and Applicable Second Lien Agent, Wilmington Trust, National Association, as Trustee under the Senior Secured Notes Indenture, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.6 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.16	Term Loan Agreement, dated as of April 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), as Borrower, the Lenders party thereto, Citibank, N.A., as Administrative Agent and Collateral Agent, and Citigroup Global Markets Inc. and J.P. Morgan Securities LLC, as Co-Lead Arrangers (Exhibit 10.7 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.17	Guarantee Agreement, dated as of April 24, 2012, by and between Everest Acquisition Finance Inc., as Guarantor, and Citibank, N.A., as collateral agent for the Secured Parties referred to therein (Exhibit 10.8 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.18	Collateral Agreement, dated as of May 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as Collateral Agent (Exhibit 10.9 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.19	Pledge Agreement, dated as of May 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as Collateral Agent (Exhibit 10.10 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.20	Amendment No. 1, dated as of August 21, 2012, to the Term Loan Agreement, dated as of April 24, 2012, among EP Energy LLC, the lenders party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.16 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).

10.21	Joinder Agreement, dated as of August 21, 2012, among Citibank, N.A., as Additional Tranche B-1 Lender, EP Energy LLC and Citibank, N.A., as administrative agent (Exhibit 10.17 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.22	Incremental Facility Agreement, dated October 31, 2012, to the Term Loan Agreement, dated as of April 24, 2012 and amended by that certain Amendment No. 1 dated as of August 21, 2012, among EP Energy LLC, the lenders from time to time party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to EP Energy LLC's Current Report on Form 8-K, filed with the SEC on November 5, 2012).
10.23	Reaffirmation Agreement, dated as of October 31, 2012, among EP Energy LLC, each Subsidiary Party party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.2 to EP Energy LLC's Current Report on Form 8-K, filed with the SEC on November 5, 2012).
10.24	Amendment No. 2, dated as of May 2, 2013, to the Term Loan Agreement, dated as of April 24, 2012, among EP Energy LLC, the lenders party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to EP Energy LLC's Current Report on Form 8-K filed with the SEC on May 28, 2013).
10.25	Joinder Agreement, dated as of May 2, 2013, among Citibank, N.A., as Additional Tranche B-1 Lender, EP Energy LLC and Citibank, N.A., as administrative agent (Exhibit 10.2 to EP Energy LLC's Current Report on Form 8-K filed with the SEC on May 28, 2013).
10.26	Pari Passu Intercreditor Agreement, dated as of May 24, 2012, among Citibank, N.A., as Second Lien Agent, Citibank, N.A., as Authorized Representative for the Term Loan Agreement, Wilmington Trust, National Association, as the Initial Other Authorized Representative and each additional Authorized Representative from time to time party hereto (Exhibit 10.12 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.27	Consent and Exchange Agreement, dated as of August 24, 2016, among EP Energy LLC, the other credit parties party thereto, the lenders party thereto, the additional lender party thereto, and Citibank, N.A. (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.28	Guarantee Agreement, dated as of August 24, 2016, among each Subsidiary of EP Energy LLC listed therein and Citibank, N.A., as collateral agent (Exhibit 10.2 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).

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Exhibit No.	Exhibit Description
10.29	Collateral Agreement, dated as of August 24, 2016, among EP Energy LLC, each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as collateral agent (Exhibit 10.3 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.30	Pledge Agreement, dated as of August 24, 2016, among EP Energy LLC, each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as collateral agent (Exhibit 10.4 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.31	Amended and Restated Senior Lien Intercreditor Agreement, dated as of August 24, 2016, among JP Morgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Citibank, N.A., as Term Facility Agent and Applicable Second Lien Agent, Citibank, N.A., as Priority Lien Term Facility Agent, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.5 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.32	Priority Lien Intercreditor Agreement, dated as of August 24, 2016, among JP Morgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Citibank, N.A., as Term Facility Agent and Applicable Second Lien Agent, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.6 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.33	Additional Priority Lien Intercreditor Agreement, dated as of November 29, 2016, by and among JPMorgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Wilmington Trust, National Association, as Notes Facility Agent and Applicable Second Lien Agent, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.1 to Company's Current Report on Form 8-K filed with the SEC on November 30, 2016).
10.34	Consent and Acknowledgement, dated as of November 29, 2016, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Citibank, N.A., as Applicable Second Lien Agent, and EP Energy LLC, with respect to the Priority Lien Intercreditor Agreement dated as of August 24, 2016 (Exhibit 10.2 to Company's Current Report on Form 8-K filed with the SEC on November 30, 2016).
10.35	Consent and Acknowledgement, dated as of November 29, 2016, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Citibank, N.A., as Applicable Second Lien Agent, and EP Energy LLC, with respect to the Amended and Restated Senior Lien Intercreditor Agreement dated as of August 24, 2016 (Exhibit 10.3 to Company's Current Report on Form 8-K filed with the SEC on November 30, 2016).
10.36	Consent and Acknowledgement, dated as of February 6, 2017, by Wilmington Trust, National Association, as new Term Facility Agent and Applicable Second Lien Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Citibank, N.A., as prior Term Facility

	Agent and prior Applicable Second Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and EP Energy LLC, with respect to the Priority Lien Intercreditor Agreement, dated as of August 24, 2016 and supplemented on November 29, 2016 (Exhibit 10.1 to Company's Report on Form 8-K, filed with the SEC on February 7, 2017).
10.37	Consent and Acknowledgement, dated as of February 6, 2017, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Savings Fund Society, FSB (as successor to Citibank, N.A.), as Applicable Second Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and EP Energy LLC, with respect to the Amended and Restated Senior Lien Intercreditor Agreement, dated as of August 24, 2016 and supplemented on November 29, 2016 (Exhibit 10.2 to Company's Current Report on Form 8-K, filed with the SEC on February 7, 2017).
10.38	Consent and Acknowledgement, dated as of January 3, 2018, by Wilmington Trust, National Association, as an Other Second-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% 2024 Notes, Wilmington Trust, National Association, as Term Facility Agent for the holders of the 8.00% 2025 Notes and Applicable Second Lien Agent and EP Energy LLC (on behalf of itself and its subsidiaries), with respect to the Priority Lien Intercreditor Agreement dated as of August 24, 2016 and supplemented on November 29, 2016 and February 6, 2017 (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on January 4, 2018).
10.39	Consent and Acknowledgement, dated as of January 3, 2018, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Savings Fund Society, FSB (as successor to Citibank, N.A.), as Applicable Second Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% 2024 Notes, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% 2025 Notes, and EP Energy LLC (on behalf of itself and its subsidiaries), with respect to the Amended and Restated Senior Lien Intercreditor Agreement dated as of August 24, 2016 and supplemented on November 29, 2016 and February 6, 2017 (Exhibit 10.2 to Company's Current Report on Form 8-K, filed with the SEC on January 4, 2018).

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Exhibit No.	Exhibit Description
10.40	Collateral Agreement, dated as of November 29, 2016, by and among EP Energy LLC, the Subsidiaries of EP Energy LLC party thereto and Wilmington Trust, National Association, as collateral agent (Exhibit 10.4 to Company's Current Report on Form 8-K, filed with the SEC on November 30, 2016).
10.41	Collateral Agreement, dated as of February 6, 2017, by and among EP Energy LLC, the Subsidiaries of EP Energy LLC party thereto and Wilmington Trust, National Association, as collateral agent (Exhibit 10.3 to Company's Current Report on Form 8-K, filed with the SEC on February 7, 2017).
10.42	Pledge Agreement, dated as of November 29, 2016, by and among EP Energy LLC, the Subsidiaries of EP Energy LLC party thereto and Wilmington Trust, National Association, as collateral agent (Exhibit 10.5 to Company's Current Report on Form 8-K filed with the SEC on November 30, 2016).
10.43	Pledge Agreement, dated as of February 6, 2017, by and among EP Energy LLC, the Subsidiaries of EP Energy LLC party thereto and Wilmington Trust, National Association, as collateral agent (Exhibit 10.4 to Company's Current Report on Form 8-K, filed with the SEC on February 7, 2017).
10.44	Amended and Restated Management Fee Agreement, dated as of December 20, 2013, among EP Energy Corporation, EP Energy Global LLC, EPE Acquisition, LLC, Apollo Management VII, L.P., Apollo Commodities Management, L.P., With Respect to Series I, Riverstone V Everest Holdings, L.P., Access Industries, Inc. and Korea National Oil Corporation (Exhibit 10.23 to Amendment No. 4 to the Company's Registration Statement on Form S-1, filed with the SEC on January 6, 2014).
10.45+	Employment Agreement dated as of November 1, 2017 by and between EP Energy Corporation and Russell Parker (Exhibit 10.1 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.46+	Employment Agreement dated as of November 1, 2017 by and between EP Energy Corporation and Ray Ambrose (Exhibit 10.2 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.47+	Employment Agreement dated as of November 1, 2017 by and between EP Energy Corporation and Chad England (Exhibit 10.3 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.48+	Employment Agreement dated May 24, 2012 for Clayton A. Carrell (Exhibit 10.18 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.49+	Employment Agreement dated May 24, 2012 for Brent J. Smolik (Exhibit 10.20 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.50+	Employment Agreement dated May 24, 2012 for Dane E. Whitehead (Exhibit 10.21 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).

10.51+	Employment Agreement dated May 24, 2012 for Marguerite N. Woung-Chapman (Exhibit 10.22 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.52+	Employment Agreement dated May 24, 2012 for Joan M. Gallagher (Exhibit 10.30 to Company's Annual Report on Form 10-K filed with the SEC on February 23, 2015).
10.53+	Senior Executive Survivor Benefit Plan adopted as of May 24, 2012 (Exhibit 10.23 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.54+	Management Incentive Plan Agreement, dated as of August 30, 2013, between EP Energy Corporation and EPE Employee Holdings, LLC (Exhibit 10.31 to Amendment No. 2 to the Company's Registration Statement on Form S-1, filed with the SEC on November 1, 2013).†
10.55+	Form of EPE Employee Holdings, LLC Management Incentive Unit Agreement (Exhibit 10.26 to EP Energy LLC's Registration Statement on Form S-4 filed with the SEC on September 11, 2012).
10.56+	Form of Notice to MIPs Holders regarding Corporate Reorganization (Exhibit 10.33 to the Company's Registration Statement on Form S-1, filed with the SEC on September 4, 2013).
10.57+	Third Amended and Restated Limited Liability Company Agreement of EPE Employee Holdings, LLC dated as of August 30, 2013 (Exhibit 10.34 to Amendment No. 2 to the Company's Registration Statement on Form S-1, filed with the SEC on November 1, 2013).†
10.58+	Form of EP Energy Employee Holdings II, LLC Class B Incentive Pool Program Award Agreement (Exhibit 10.37 to Amendment No. 1 to the Company's Registration Statement on Form S-1, filed with the SEC on October 11, 2013).
10.59+	EP Energy Corporation 2014 Omnibus Incentive Plan, as amended and restated effective May 11, 2016 (Exhibit 10.1 to EP Energy Corporation's Current Report on Form 8-K, filed with the SEC on May 13, 2016).

10.60+	Form of Notice Stock Option Grant and Stock Option Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.39 to Company's Annual Report on Form 10-K filed with the SEC on February 27, 2014).

Exhibit No.	Exhibit Description
10.61+	Form of Notice Restricted Stock Grant and Restricted Stock Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.40 to Company's Annual Report on Form 10-K filed with the SEC on February 28, 2014).
10.62+	Form of Performance Unit Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan. (Exhibit 10.42 to Company's Annual Report on Form 10-K filed with the SEC on February 22, 2016).
10.63+	Form of 2017 Performance Unit Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.52 to Company's Annual Report on Form 10-K filed with the SEC on March 3, 2017).
10.64+	EP Energy Corporation Employment Inducement Plan (Exhibit 10.4 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.65+	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement under the EP Energy Corporation Employment Inducement Plan (Exhibit 10.5 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.66+	Form of Restricted Stock Grant Notice and Restricted Stock Agreement under the EP Energy Corporation Employment Inducement Plan (Exhibit 10.6 to Company's Current Report on Form 8-K filed with the SEC on November 2, 2017).
10.67	Stockholders Agreement, dated as of August 30, 2013, between EP Energy Corporation and the stockholders party thereto (Exhibit 10.39 to Amendment No. 1 to the Company's Registration Statement on Form S-1, filed with the SEC on October 11, 2013).
10.68	Addendum Agreement, dated as of September 18, 2013, to the Stockholders Agreement, between EP Energy Corporation and EP Energy Employee Holdings II, LLC (Exhibit 10.40 to Amendment No. 1 to the Company's Registration Statement on Form S-1, filed with the SEC on October 11, 2013).
10.69	Form of Director and Officer Indemnification Agreement between EP Energy Corporation and each of the officers and directors thereof (Exhibit 10.41 to Amendment No. 4 to the Company's Registration Statement on Form S-1, filed with the SEC on January 6, 2014).
12.1*	Ratio of Earnings to Fixed Charges.
21.1*	Subsidiaries of EP Energy Corporation.
23.1*	Consent of Ernst & Young LLP, an independent registered public accounting firm.

23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Ryder Scott Company, L.P. reserve audit report for EP Energy Corporation as of December 31, 2017.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

(c) Financial statement schedules

Financial statement schedules have been omitted because they are either not required or not applicable.

ITEM 16. FORM 10-K SUMMARY

None.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, EP Energy Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 1st day of March 2018.

EP ENERGY CORPORATION

By: /s/ Russell E. Parker
Russell E. Parker
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of EP Energy Corporation and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ Russell E. Parker Russell E. Parker	President, Chief Executive Officer and Director (Principal Executive Officer)	March 1, 2018
/s/ Kyle A. McCuen Kyle A. McCuen	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	March 1, 2018
/s/ Francis C. Olmsted III Francis C. Olmsted III	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 1, 2018
/s/ Alan R. Crain, Jr. Alan R. Crain, Jr.	Chairman of the Board	March 1, 2018
/s/ Gregory A. Beard Gregory A. Beard	Director	March 1, 2018
/s/ Scott R. Browning Scott R. Browning	Director	March 1, 2018
/s/ Wilson B. Handler Wilson B. Handler	Director	March 1, 2018
/s/ John J. Hannan John J. Hannan	Director	March 1, 2018
/s/ J. Barton Kalsu J. Barton Kalsu	Director	March 1, 2018
/s/ Rajen Mahagaokar Rajen Mahagaokar	Director	March 1, 2018

/s/ Giljoon Sinn Giljoon Sinn	Director	March 1, 2018
/s/ Robert M. Tichio Robert M. Tichio	Director	March 1, 2018
/s/ Donald A. Wagner Donald A. Wagner	Director	March 1, 2018
/s/ Rakesh Wilson Rakesh Wilson	Director	March 1, 2018

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