PDC ENERGY, INC.
Form 10-K
February 28, 2019

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

FORM 10-K

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

For the fiscal year ended December 31, 2018

or

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

For the transition period from __________ to _________

Commission File Number 001-37419
PDC ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	95-2636730
(State of incorporation)	(I.R.S. Employer Identification No.)

1775 Sherman Street, Suite 3000
Denver, Colorado 80203
(Address of principal executive offices) (Zip code)

Registrant's telephone number, including area code: (303) 860-5800

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	NASDAQ Global Select Market

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 T No £

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

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 T No £

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes T No £

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of 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. T

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer x Accelerated filer o
Non-accelerated filer £ 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. £

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2018 was $4.0 billion (based on the closing price of $60.45 per share as of the last business day of the fiscal quarter ending June 30, 2018).

As of February 15, 2019, there were 66,148,128 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

We hereby incorporate by reference into this document the information required by Part III of this Form, which will appear in our definitive proxy statement filed pursuant to Regulation 14A for our 2019 Annual Meeting of Stockholders.

PDC ENERGY, INC.
2018 ANNUAL REPORT ON FORM 10-K
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PART I

REFERENCES TO THE REGISTRANT

Unless the context otherwise requires, references in this report to "PDC," the "Company," "we," "us," "our" or "ours" refer to the registrant, PDC Energy, Inc., our wholly-owned subsidiaries consolidated for the purposes of its financial statements, including our proportionate share of the financial position, results of operations, cash flows and operating activities of our affiliated partnerships. PDC Energy, Inc. is a Delaware corporation, having reincorporated from Nevada in 2015.

GLOSSARY OF UNITS OF MEASUREMENTS AND INDUSTRY TERMS

Units of measurements and industry terms are defined in the Glossary of Units of Measurements and Industry Terms, included at the end of this report.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical fact included in and incorporated by reference into this report are "forward-looking statements." Words such as expect, anticipate, intend, plan, believe, seek, estimate, schedule and similar expressions or variations of such words are intended to identify forward-looking statements herein. Forward-looking statements include, among other things, statements regarding future: production, costs and cash flows; drilling locations, zones and growth opportunities; commodity prices and differentials; capital expenditures and projects, including the number of rigs employed, and that cash flows from operations will exceed expected capital investments in crude oil and natural gas properties for 2019 and 2020; management of lease expiration issues; financial ratios and compliance with covenants in our revolving credit facility and other debt instruments; impacts of certain accounting and tax changes; anticipated sale of our Delaware Basin midstream assets and the timing of those sales; midstream capacity and related curtailments; fractionation capacity; impacts of Colorado political matters; ability to meet our volume commitments to midstream providers; ongoing compliance with our consent decree; reclassification of the Denver Metro/North Front Range NAA ozone classification to serious; and timing and adequacy of infrastructure projects of our midstream providers.

The above statements are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Forward-looking statements are always subject to risks and uncertainties, and become subject to greater levels of risk and uncertainty as they address matters further into the future. Throughout this report or accompanying materials, we may use the term “projection” or similar terms or expressions, or indicate that we have “modeled” certain future scenarios. We typically use these terms to indicate our current thoughts on possible outcomes relating to our business or the industry in periods beyond the current fiscal year. Because such statements relate to events or conditions further in the future, they are subject to increased levels of uncertainty.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- changes in global production volumes and demand, including economic conditions that might impact demand and prices for products we produce;
- volatility of commodity prices for crude oil, natural gas and natural gas liquids ("NGLs") and the risk of extended periods of depressed prices;

- volatility and widening of differentials;
- reductions in the borrowing base under our revolving credit facility;
- impact of governmental policies and/or regulations, including changes in environmental and other laws, the interpretation and enforcement related to those laws and regulations, liabilities arising thereunder and the costs to comply with those laws and regulations;
- declines in the value of our crude oil, natural gas and NGLs properties resulting in impairments;
- changes in estimates of proved reserves;
- inaccuracy of estimated reserves and production rates;
- potential for production decline rates from our wells being greater than expected;
- timing and extent of our success in discovering, acquiring, developing and producing reserves;

- availability of sufficient pipeline, gathering and other transportation facilities and related infrastructure to process and transport our production and the impact of these facilities and regional capacity on the prices we receive for our production;
- timing and receipt of necessary regulatory permits;
- risks incidental to the drilling and operation of crude oil and natural gas wells;
- difficulties in integrating our operations as a result of any significant acquisitions and acreage exchanges;
- availability of supplies, materials, contractors and services that may delay the drilling or completion of our wells;
- potential losses of acreage due to lease expirations or otherwise;
- increases or changes in costs and expenses;
- future cash flows, liquidity and financial condition;
- possibility that one or more sales of our Delaware Basin midstream assets will not close as expected;
- competition within the oil and gas industry;
- availability and cost of capital;
- our success in marketing crude oil, natural gas and NGLs;
- effect of crude oil, natural gas and NGLs derivatives activities;
- impact of environmental events, governmental and other third-party responses to such events and our ability to insure adequately against such events;
- cost of pending or future litigation;
- effect that acquisitions we may pursue have on our capital requirements;
- our ability to retain or attract senior management and key technical employees; and
- success of strategic plans, expectations and objectives for our future operations.

Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under Item 1A, Risk Factors, made in this report and our other filings with the U.S. Securities and Exchange Commission ("SEC") for further information on risks and uncertainties that could affect our business, financial condition, results of operations and cash flows. We caution you not to place undue reliance on forward-looking statements, which speak only as of the date of this report. We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events. All forward-looking statements are qualified in their entirety by this cautionary statement.

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

The Company

We are a domestic independent exploration and production company that acquires, explores and develops properties for the production of crude oil, natural gas and NGLs, with operations in the Wattenberg Field in Colorado and the Delaware Basin in Texas. Our operations in the Wattenberg Field are focused in the horizontal Niobrara and Codell plays and our Delaware Basin operations are primarily focused in the Wolfcamp zones. We previously operated properties in the Utica Shale in Southeastern Ohio; however, we divested these properties (the "Utica Shale Divestiture") during the first quarter of 2018.

The following map presents the general locations of our development and production activities as of December 31, 2018:

The following table presents selected information regarding our results of operations for the periods presented:

	Year Ended/As of December 31,		Percent Change
	2018	2017	2018-2017
	(production and reserves in MMBoe, dollars in millions)		
Wells:			
Gross productive wells	2,876	2,785	3.3 %
Net productive wells	2,284	2,285	— %
Horizontal percentage	39.0 %	32.0 %	21.9 %
Operated percentage	84.3 %	87.0 %	(3.1)%
Gross operated wells turned-in-line	165	146	13.0 %
Net operated wells turned-in-line	151	128	18.0 %
Production:			
Wattenberg Field	30.7	26.8	14.3 %
Delaware Basin	9.4	4.2	123.7 %
Utica Shale (1)	0.1	0.8	(82.1)%
Total	40.2	31.8	26.2 %
Reserves:			
Proved reserves	544.9	452.9	20.3 %
Proved developed reserves percentage	32.9 %	31.6 %	4.1 %
Liquidity	$1,268.9	$880.7	44.1 %
Leverage ratio	1.4	1.9	(26.3)%

(1) In March 2018, we completed the disposition of our Utica Shale properties.

Our Strengths

- Significant project inventory in premier crude oil, natural gas and NGL plays. We have a considerable operational presence in two premier U.S. onshore basins, the Wattenberg Field in Weld County, Colorado, and the Delaware Basin in Reeves and Culberson Counties, Texas. We have identified an inventory of horizontal drilling locations in each basin which we believe will allow us to continue to grow our proved reserves and production at attractive rates of return. Such expected returns can vary well by well and are based upon many factors, including, but not limited to commodity prices, drilling rig pace and well development and operating costs. Our 2019 drilling and completion operations are expected to continue to focus on the areas in which we expect to deliver our strongest economic results, which include the Kersey area of the Wattenberg Field and in the oilier eastern and north central areas of the Delaware Basin.

- Strong financial position. We expect to maintain a disciplined financial strategy, consisting of strong liquidity, low leverage ratios and an active commodity derivative program to help mitigate a portion of the risk associated with commodity price fluctuations. As of December 31, 2018, we had a total liquidity position of $1.3 billion, comprised of $1.4 million of cash and cash equivalents and $1.3 billion available for borrowing under our revolving credit facility, a leverage ratio, as defined in our revolving line of credit facility agreement, of 1.4, and commodity derivative positions covering 11.0 MMBbls and 8.6 MMBbls of crude oil production for 2019 and 2020, respectively. As of the same date, we had hedged approximately 26.4 Bcf of natural gas for 2019.

- Balanced and diversified portfolio across two premier U.S. onshore basins. Having drilling opportunities in both the Wattenberg Field and the Delaware Basin allows us to allocate capital between the two areas to diversify our risk. We believe this will improve our overall financial results and drive our future production and reserve growth. Additionally, we believe the geographical diversity of our portfolio aids in the mitigation of risks associated with a single dominant producing area, as each basin has its own operating and competitive dynamic in terms of commodity price markets, service costs, takeaway capacity and regulatory and political considerations.

- Significant operational control in our core areas. We have, and expect to continue to have, a substantial degree of operational control over our properties. As a result of successfully executing our strategy of acquiring and consolidating largely concentrated acreage positions with high working interests, we operate and manage approximately 84 percent of all wells in which we have an interest across all of our operating basins. Our control allows us to manage our drilling, production, operating and administrative costs and to leverage our technical expertise in our core operating areas. Our leaseholds that are held by production further enhance our operational control by providing us flexibility in selecting drilling locations based upon various operational criteria.

- Efficiency through technology and consolidation. Technological innovation has led to continued improvement in our Wattenberg Field and Delaware Basin drilling times. These improvements in drilling efficiency have resulted from a combination of highly technical drilling services and equipment and continuity within our operations team. After several years of drilling horizontal wells, our drilling operations in the Wattenberg Field have shown strong results. We are in the process of applying our extensive experience in drilling highly-successful wells in the Wattenberg Field to our growing Delaware Basin operations.

The technology associated with our completions process is also improving as wellbore placement and stage spacing continue to advance. In addition, completion equipment, perforation clusters, fluid and sand type and concentration decisions continue to result in increased estimated ultimate recoveries of crude oil and natural gas reserves. As with our drilling operations, we are currently working toward using the expertise we have developed in the Wattenberg Field to increase the efficiency of our Delaware Basin completions activities.

Also key to our efficiency, we occasionally enter into acquisitions and exchanges that provide acreage consolidation, particularly in the Wattenberg Field, where we continue to drill longer length lateral wells. Longer length lateral wells are more cost effective and reduce the impact on the surface through fewer wells and reduced truck traffic, both of which also provide enhanced efficiencies and are beneficial to the communities in which we operate.

- Strong environmental, health and safety compliance programs and community outreach. We have focused on establishing effective environmental, health and safety programs that are intended to promote safe working practices for our employees and contractors and to help earn the trust and respect of land owners, regulatory agencies and public officials. This is an important part of our strategy in effectively operating in today’s intensive regulatory and public debate climate. We are also dedicated to being an active and contributing member of the communities in which we

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operate. We share our success with these communities in various ways, including charitable giving and community event sponsorships.

- Strong management team and operational capabilities. We have strong and stable management, led by our executive management team. Each member of the team has between 10 and 30 years of experience in the energy and natural resource industry. This experience collectively spans land, reservoir analysis, operations, accounting, strategy and general operations, and has helped us continue our growth through periods of commodity price pressure and cost inflation and other challenging environments.

Long-Term Business Strategy

Our long-term business strategy focuses on being a responsible and respected provider of energy while generating stockholder value through the exploration and development of crude oil and natural gas properties. We leverage technology and innovation to increase operational efficiencies while prioritizing health, safety and the environment and are focused on the growth of our cash flows, production and reserves, primarily through organic exploration and development of our existing leasehold. We focus on horizontal development drilling programs in resource plays that offer repeatable results and the potential for attractive returns on investment in a range of commodity price environments. Our creation and maintenance of a high-value inventory of drilling locations supports our planned organic growth over the next several years.

In addition to development drilling, we routinely review acquisition and acreage swap opportunities in our core areas of operations and pursue those that meet our strategic plan and that we believe will increase stockholder value. We believe we can extract additional value from such transactions through the addition of more extended reach lateral wells, related production optimization opportunities and increases in our working interests in our development drilling locations afforded by more concentrated acreage positions. Once we have established a significant presence in an area, the use of bolt-on acquisitions and acreage exchanges provides synergies that result in additional economies of scale.

We also maintain a limited and disciplined exploration program with the goal of replenishing our portfolio with new potential drilling locations capable of positioning us for significant production and reserve growth in future years. When doing so, we attempt to accumulate significant leasehold positions before competitive forces drive up the cost of entry and to invest in leasehold positions that are near existing or emerging midstream infrastructure. Our recent exploration activity has been in the Delaware Basin as there are multiple zones that have not seen development sufficient to record proved reserves, such as the Bone Spring and Wolfcamp C zones.

We pursue various midstream, marketing and cost reduction initiatives designed to increase our operating margins, while maintaining a disciplined financial strategy focused on providing a strong financial foundation for the execution of our business strategy.

Operating Areas

Wattenberg Field. In the Wattenberg Field, we have identified a gross operated inventory of approximately 920 horizontal drilling locations with an average lateral length of approximately 8,300 feet. In addition to these drilling locations, we entered 2019 with approximately 135 gross operated drilled uncompleted wells ("DUCs"). Our inventory of Wattenberg Field locations declined in 2018 as a result of our 2018 drilling program and two significant acreage exchanges. Although these acreage exchanges reduced our inventory of gross drilling locations, they increased both our working interest ownership in, and the average lateral length of, the remaining locations. Our average working interest in our Wattenberg Field properties that we operate is approximately 79 percent. Our Wattenberg Field horizontal drilling locations have been substantially de-risked through multiple years of successful development from the field. Substantially all of our Wattenberg Field acreage is held by production. Wells in the

Wattenberg Field typically have productive horizons at depths of approximately 6,500 to 7,500 feet below the surface.

Delaware Basin. In the Delaware Basin, we have identified a gross operated inventory of approximately 365 horizontal drilling locations, primarily targeting the Wolfcamp A and Wolfcamp B zones within our oilier eastern and north central areas. The average lateral length of these locations is approximately 7,900 feet. Some of these locations are within untested target zones that may be subject to a higher degree of uncertainty or may depend upon additional delineation and testing. In addition to these drilling locations, we entered 2019 with approximately 20 gross operated DUCs. Wells in the Delaware Basin typically have productive horizons at depths of approximately 8,000 to 11,500 feet below the surface.

Our average working interest in our Delaware Basin properties that we operate is approximately 83 percent. Our leasehold in the Delaware Basin requires a more active drilling program than the Wattenberg Field in terms of managing lease expirations. In some cases, continuous operations will be required to maintain the underlying leasehold in the Delaware Basin. However, with our high percentage of operated leasehold in the area, we expect to have adequate control over the location and pace of our development to manage lease expirations and meet our drilling obligations in the central and eastern parts of our acreage position.

We are in the process of actively marketing our Delaware Basin crude oil gathering, natural gas gathering and produced water gathering and disposal assets for sale and currently expect to execute agreements for the sales of these assets in the first half of 2019.

2019 Strategic Focus

Our planned 2019 capital investments in crude oil and natural gas properties, which we expect to be between $810 million and $870 million, are focused on continued execution of our development plans in the Wattenberg Field and Delaware Basin. In allocating our planned expenditures, we consider, among other things, expected rates of return, the political environment and our remaining inventory in order to best meet our short- and long-term corporate goals.

As a result of this disciplined approach, we expect that cash flows from operations in 2019 will exceed our capital investments in crude oil and natural gas properties, which exclude investments in corporate capital, by approximately $65.0 million. This expectation is based on our current production forecast for 2019 and our average 2019 price assumptions of $55.00 for New York Mercantile Exchange ("NYMEX") crude oil and $3.00 for NYMEX natural gas. Assuming a NYMEX crude oil price of $50.00, we expect cash flows from operations to exceed our capital investments in crude oil and natural gas properties by approximately $25.0 million. We anticipate that capital investments will exceed cash flows from operations during the first half of 2019 and expect cash flows from operations to exceed capital investment during the remainder of the year. Our leverage ratio, as defined in our revolving credit facility agreement, is expected to decrease from 1.4 as of the end of 2018 to approximately 1.3 by the end of 2019 based on our anticipated production and $50.00 to $55.00 NYMEX crude oil prices.

Assuming a NYMEX crude oil price of $45.00, we expect cash flows from operations to approximate our capital investments in crude oil and natural gas properties. A significant decline in NYMEX crude oil prices below approximately $45.00 per barrel would negatively impact our results of operations, financial condition and future development plans. We may revise our 2019 capital investment program during the year as a result of, among other things, changes in commodity prices or our internal long-term outlook for commodity prices, the cost of services for drilling and well completion activities, requirements to hold acreage, drilling results, changes in our borrowing capacity, a significant change in cash flows, regulatory issues, requirements to maintain continuous activity on leaseholds or acquisition and/or divestiture opportunities.

In 2019, we also expect to spend approximately $20 million for corporate capital, the majority of which is related to the implementation of an enterprise resource planning (“ERP”) system to replace our existing operating and financial systems. This long-planned investment is being made to enhance maintenance of our financial records, improve operational functionality and provide timely information to our management team related to the operation of the business.

Recent Strategic Developments

We closed an acquisition of properties from Bayswater Exploration and Production LLC (the "Bayswater Asset Acquisition") in January 2018, acquiring approximately 7,400 net acres, 24 operated horizontal wells that were either DUCs or in-process wells at the time of closing and approximately 220 gross drilling locations.

During 2018, we completed two acreage exchanges that consolidated our position in the core area of the Wattenberg Field, resulting in us acquiring approximately 14,800 net acres in exchange for 15,500 net acres.

Business Segments

We are engaged in two operating segments: our oil and gas exploration and production segment and our gas marketing segment. All of our material operations are attributable to our exploration and production business; therefore, our operations are presented as a single segment for all periods presented. Our most significant customer is DCP Midstream, LP ("DCP"). Sales to this party constituted more than 10 percent of our 2018 revenues. Given the liquidity in the market for the sale of hydrocarbons, however, we believe that the loss of any purchaser or the aggregate loss of several customers could be managed by selling to alternative purchasers.

Properties

Productive Wells

The following table presents our productive wells:

	Productive Wells As of December 31, 2018					
	Crude Oil		Natural Gas		Total	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net
Wattenberg Field	1,044	706.0	1,746	1,506.7	2,790	2,212.7
Delaware Basin	43	29.8	43	41.2	86	71.0
Total productive wells	1,087	735.8	1,789	1,547.9	2,876	2,283.7

Proved Reserves

The following table presents our proved reserve estimates as of December 31, 2018, based on reserve reports prepared by our independent petroleum engineering consulting firms, Ryder Scott Company, L.P. ("Ryder Scott") and Netherland, Sewell & Associates, Inc. ("NSAI") and related information:

	Proved Reserves at December 31, 2018							
	Proved Reserves (MMBoe)	% of Total Proved Reserves		% Proved Developed		% Liquids		Proved Reserves to Production Ratio (in years)(1)	2018 Production (MBoe)
Wattenberg Field	425.4	78	%	33	%	57	%	13.9	30,652
Delaware Basin	119.5	22	%	34	%	68	%	12.8	9,359
Utica Shale (2)	—	—	%	—	%	—	%	—	149
Total	544.9	100	%	33	%	59	%	13.6	40,160

(1) Based on 2018 production.
(2) In March 2018, we completed the disposition of our Utica Shale properties.

Our proved reserves are sensitive to future crude oil, natural gas and NGLs sales prices and the related effect on the economic productive life of producing properties. Increases in commodity prices may result in a longer economic productive life of a property or result in recognition of more economically viable proved undeveloped ("PUD") reserves, while decreases in commodity prices may result in negative impacts of this nature. All of our proved reserves are located in the U.S.

Controls Over Reserve Report Preparation. Our proved reserve estimates are prepared using the definitions for proved reserves set forth in SEC Regulation S-X, Rule 4-10(a) and other applicable SEC rules. Inputs and major assumptions related to our proved reserves are reviewed annually by an internal team composed of reservoir engineers, geologists, land and management for adherence to SEC guidelines through a detailed review of land and accounting records, available geological and reservoir data and production performance data. The internal team compiles the reviewed data and forwards the applicable data to Ryder Scott or NSAI. Our proved reserves in the Wattenberg Field as of December 31, 2018 were estimated by Ryder Scott and our proved reserves in the Delaware Basin as of that date were estimated by NSAI.

When preparing our reserve estimates, neither Ryder Scott nor NSAI independently verifies the accuracy and completeness of information and data furnished by us with respect to ownership interests, production volumes, well test data, historical costs of operations and development, product prices or any agreements relating to current and future operations of properties or sales of production. Ryder Scott and NSAI prepare estimates of our reserves in conjunction with an ongoing review by our engineers. A final comparison of data is performed to ensure that the reserve estimates are complete, determined pursuant to acceptable industry methods, and with a level of detail we deem appropriate. The final estimated reserve reports are prepared by Ryder Scott and NSAI and reviewed by our engineering staff and management prior to issuance by those firms.

Letters which identify the professional qualifications of the individuals at Ryder Scott and NSAI who are responsible for overseeing the preparation of our reserve estimates as of December 31, 2018 have been filed as Exhibits 99.1 and 99.2 to this report.

Internally, the professional qualifications of our lead engineer primarily responsible for overseeing the preparation of our reserve estimates, as defined in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information as promulgated by the Society of Petroleum Engineers, qualifies this individual as a Reserve Estimator. This person holds a Masters of Petroleum Engineering from the Colorado School of Mines and a Bachelors of Geology from the University of Colorado and has over 18 years of oil and gas experience.

In determining our proved reserves estimates, we used a combination of performance methods, including decline curve analysis and other computational methods, offset analogies and seismic data and interpretation. All of our proved undeveloped reserves conform to the SEC five-year rule requirement as all proved undeveloped locations are scheduled, according to an adopted development plan, to be drilled within five years of the location's initial booking date.

Commodity Pricing. Per SEC rules, the pricing used to prepare the proved reserves is based on the unweighted arithmetic average of the first of the month prices for the preceding 12 months. The NYMEX prices used in preparing the reserves are then adjusted based on energy content, location and basis differentials and other marketing deductions to arrive at the net realized price.

The indicated index prices for our reserves, by commodity, are presented below.

	Average Benchmark Prices (1)		
As of December 31,	Crude Oil (per Bbl) (2)	Natural Gas (per Mcf) (2)	NGLs (per Bbl) (3)
2018	$65.56	$ 3.10	$65.56
2017	51.34	2.98	51.34
2016	42.75	2.48	42.75

The netted back price used to estimate our reserves, by commodity, are presented below.

	Price Used to Estimate Reserves (4)		
As of December 31,	Crude Oil (per Bbl)	Natural Gas (per Mcf)	NGLs (per Bbl)
2018	$61.14	$ 2.15	$23.04
2017	48.68	2.31	20.21
2016	38.67	1.85	11.97

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(1) Per SEC rules, the pricing used to prepare the proved reserves is based on the unweighted arithmetic average of the first of the month prices for the preceding 12 months.

(2) Our benchmark prices for crude oil and natural gas are West Texas Intermediate ("WTI") and Henry Hub, respectively.

(3) For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes.

(4)

These prices are based on the index prices and are net of basin differentials, transportation fees, contractual adjustments and Btu adjustments we experienced for the respective commodity.

Commodities and Standardized Measure. Reserve estimates involve judgments and reserves cannot be measured exactly. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geologic and geophysical data and economic changes. Neither the estimated future net cash flows nor the standardized measure of discounted future net cash flows ("standardized measure") is intended to represent the current market value of our proved reserves. For additional information regarding both of these measures, as well as other information regarding our proved reserves, see the Supplemental Information Unaudited - Crude Oil and Natural Gas Information provided with our consolidated financial statements included elsewhere in this report.

The following tables provide information regarding our estimated proved reserves:

	As of December 31,		
	2018	2017	2016
Proved reserves			
Crude oil and condensate (MMBbls)	190	155	118
Natural gas (Bcf)	1,336	1,154	834
NGLs (MMBbls)	132	106	84
Total proved reserves (MMBoe)	545	453	341
Proved developed reserves (MMBoe)	180	143	98
Estimated undiscounted future net cash flows (in millions) (1)	$7,735	$5,453	$2,681
Standardized measure (in millions)	$4,448	$2,880	$1,421
PV-10 (in millions) (2)	$5,321	$3,212	$1,675

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(1) Amount represents aggregate undiscounted future net cash flows, before income taxes, estimated by Ryder Scott and NSAI, of approximately $9.1 billion, $6.2 billion and $3.3 billion as of December 31, 2018, 2017 and 2016, respectively, less an internally-estimated undiscounted future income tax expense of approximately $1.4 billion, $0.7 billion and $0.6 billion, respectively.

(2) PV-10 is a non-U.S. GAAP financial measure. It is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure reported in accordance with U.S. GAAP, but rather should be considered in addition to the standardized measure. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Reconciliation of Non-U.S. GAAP Financial Measures, for a definition of PV-10 and a reconciliation of our PV-10 value to the standardized measure.

The additions to our proved reserves at December 31, 2018 as compared to December 31, 2017 were primarily a result of extending the average lateral length of newly-drilled and expected future wells, combined with an increase in our working interest ownership in wells in areas with established reserves largely resulting from recently-completed acreage exchanges and the addition of proved undeveloped locations in the Delaware Basin.

The following table presents our estimated proved developed and undeveloped reserves by category and area:

	As of December 31, 2018				
Operating Region/Area	Crude Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Crude Oil Equivalent (MMBoe)	Percent
Proved developed					
Wattenberg Field	46.3	357.4	33.2	139.0	26 %
Delaware Basin	15.6	85.7	10.7	40.5	7 %
Total proved developed	61.9	443.1	43.9	179.5	33 %
Proved undeveloped					
Wattenberg Field	90.5	749.2	71.0	286.4	52 %
Delaware Basin	38.0	143.4	17.1	79.0	15 %
Total proved undeveloped	128.5	892.6	88.1	365.4	67 %
Total proved reserves					
Wattenberg Field	136.8	1,106.6	104.2	425.4	78 %
Delaware Basin	53.6	229.1	27.8	119.5	22 %

Total proved reserves	190.4	1,335.7	132.0	544.9	100 %

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Proved Reserves Sensitivity Analysis. We have performed an analysis of our proved reserve estimates as of December 31, 2018 to present sensitivity associated with a lower crude oil price as the value of crude oil influences the value of our proved reserves and PV-10 most significantly. Replacing the 2018 NYMEX price for crude oil used in estimating our reported proved reserves with $50.00 as shown on the table below, and leaving all other parameters unchanged, results in changes to our estimated proved reserves as shown.

	Pricing Scenario - NYMEX					
	Crude Oil (per Bbl)	Natural Gas (per MMBtu)	Proved Reserves (MMBoe)	% Change from December 31, 2018 Estimated Reserves	PV-10 (in Millions)	PV-10 % Change from December 31, 2018 Estimated Reserves
2018 SEC Reserve Report (1)	$65.56	$ 3.10	544.9	—	$5,321.3	—
Alternate Price Scenario	$50.00	$ 3.10	529.3	(3)%	$3,659.0	(31)%

(1) These prices are the SEC NYMEX prices applied to the calculation of the PV-10 value. Such prices have been applied consistently in the alternate pricing scenario to include the impact of adjusting for deductions for any basin differentials, transportation fees, contractual adjustments and Btu adjustments we experienced for the relevant commodity.

Developed and Undeveloped Acreage

The following table presents our developed and undeveloped lease acreage:

	As of December 31, 2018					
	Developed		Undeveloped		Total	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net
Wattenberg Field (1)	115,600	109,300	16,000	14,700	131,600	124,000
Delaware Basin (2)	36,100	32,300	22,300	19,100	58,400	51,400
Total acreage	151,700	141,600	38,300	33,800	190,000	175,400

(1) Of the amounts shown, 91,500 gross (86,100 net) developed lease acres and 11,100 gross (10,200 net) undeveloped lease acres are associated with our approximately 920 operated horizontal Wattenberg Field drilling locations targeting the Niobrara or Codell plays. The remaining acres are associated with other zones within the field that we do not currently estimate to be economic to develop; therefore, we have not currently identified any potential drilling locations on these acres.

(2) See below regarding Culberson County acreage expirations.

Substantially all of our undeveloped acreage in the Wattenberg Field is related to leaseholds that are held by production. Our Wattenberg Field leaseholds at risk to expire in 2019 and 2020 are not material.

In the Delaware Basin, there are drilling obligations or continuous drilling clauses associated with the majority of our acreage. We believe that our current Delaware Basin drilling plan should provide sufficient development to meet these obligations in our core areas over the next few years. In the event that we do not meet the obligations for certain leases, we plan to make any necessary bonus extension payments or changes to drilling schedules, or seek to renew or re-lease in order to retain the leases. However, the payments necessary to extend or retain certain leases may be significant and we may not be successful in such efforts or we may elect not to pursue them.

During 2017 and 2018, we recorded impairment charges totaling $285.9 million and $458.4 million, respectively, as we identified current and anticipated leasehold expirations within the Western Culberson County area of the Delaware Basin and made the determination that we would no longer pursue plans to develop these properties. The impaired non-focus leaseholds typically have a higher gas to oil ratio and a greater degree of geologic complexity than our other Delaware Basin properties. In 2019, we expect that we will allow approximately 18,300 gross (17,900 net) acres of our leaseholds in the Delaware Basin to expire. Of these leaseholds, we expect that approximately 9,500 gross and net acres and 8,600 gross (8,000 net) acres will expire in the first and third quarters, respectively, of 2019. Taking all expected 2019 expirations into account, we anticipate ending 2019 with approximately 40,100 gross (33,500 net) acres in the Delaware Basin. In 2020, we expect that we will allow approximately 3,400 gross (1,800 net) acres of our leaseholds in the Delaware Basin to expire. We are currently exploring strategic alternatives with respect to the acres expected to expire in 2019 and 2020 and believe that we may be able to monetize a portion of this acreage. See Item 1A. Risk Factors - Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Drilling Activity. The following tables set forth a summary of our developmental and exploratory well drilling activity for the periods presented. Productive wells consist of wells that were turned-in-line and commenced production during the period, regardless of when drilling was initiated. In-process wells represent wells that are in the process of being drilled or have been drilled and are waiting to be fractured and/or for gas pipeline connection as of the date shown. We utilize pad drilling operations where multiple wells are developed from the same well pad in both the Wattenberg Field and Delaware Basin. Because we operate multiple drilling rigs in each operating area, we expect to have in-process wells at any given time. Wells may be in-process for up to a year.

	Gross Development Well Drilling Activity								
	Year Ended December 31,								
	2018			2017			2016		
Operating Region/Area	Productive	In-Process	Non-Productive	Productive	In-Process	Non-Productive (1)	Productive	In-Process	Non-Productive (1)
Wattenberg Field, operated wells	139	133	—	130	87	—	140	64	2
Wattenberg Field, non-operated wells	20	5	—	12	14	1	24	12	—
Delaware Basin, operated wells	26	22	1	9	10	—	1	5	—
Delaware Basin, non-operated wells	11	—	—	2	8	—	—	—	—
Utica Shale (2)	—	—	—	—	—	—	5	—	—
Total gross development wells	196	160	1	153	119	1	170	81	2

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(1) Represents mechanical failures that resulted in the plugging and abandonment of the respective well(s).
(2) In March 2018, we completed the disposition of our Utica Shale properties.

	Net Development Well Drilling Activity								
	Year Ended December 31,								
	2018			2017			2016		
Operating Region/Area	Productive	In-Process	Non-Productive	Productive	In-Process	Non-Productive (1)	Productive	In-Process	Non-Productive (1)
Wattenberg Field, operated wells	126.8	122.4	—	112.8	80.1	—	109.7	52.7	1.7
Wattenberg Field, non-operated wells	2.5	0.9	—	1.6	2.6	0.1	5.0	2.8	—
Delaware Basin, operated wells	24.5	16.3	1.0	10.1	9.4	—	1.0	4.8	—
Delaware Basin, non-operated wells	1.2	—	—	0.4	1.0	—	—	—	—
Utica Shale (2)	—	—	—	—	—	—	4.5	—	—
Total net development wells	155.0	139.6	1.0	124.9	93.1	0.1	120.2	60.3	1.7

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(1) Represents mechanical failures that resulted in the plugging and abandonment of the respective well(s).
(2) In March 2018, we completed the disposition of our Utica Shale properties.

	Gross Exploratory Well Drilling Activity								
	Year Ended December 31,								
	2018			2017			2016		
Operating Region/Area	Productive	In-Process	Non-Productive	Productive	In-Process	Non-Productive	Productive	In-Process	Non-Productive
Wattenberg Field, operated wells	—	—	—	—	—	—	—	—	—
Wattenberg Field, non-operated wells	—	—	—	—	—	—	—	—	—
Delaware Basin	3	2	—	5	3	2	—	—	—
Total gross development wells	3	2	—	5	3	2	—	—	—

	Net Exploratory Well Drilling Activity								
	Year Ended December 31,								
	2018			2017			2016		
Operating Region/Area	Productive	In-Process	Non-Productive	Productive	In-Process	Non-Productive	Productive	In-Process	Non-Productive
Wattenberg Field, operated wells	—	—	—	—	—	—	—	—	—
Wattenberg Field, non-operated wells	—	—	—	—	—	—	—	—	—
Delaware Basin	2.8	2.0	—	3.1	2.8	2.0	—	—	—
Total gross development wells	2.8	2.0	—	3.1	2.8	2.0	—	—	—

Title to Properties

We believe that we hold good and defensible leasehold title to substantially all of our crude oil and natural gas properties, in accordance with standards generally accepted in the industry. A preliminary title examination is typically conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and remedial curative work is performed, as necessary, with respect to discovered defects which we deem to be significant, in order to procure division order title opinions. Title examinations have been performed with respect to substantially all of our producing properties.

The properties we own are subject to royalty, overriding royalty and other outstanding interests. The properties may also be subject to additional burdens, liens or encumbrances customary in the industry, including items such as operating agreements, current taxes, development obligations under crude oil and natural gas leases, farm-out agreements and other restrictions. We do not believe that any of these burdens will materially interfere with our use of the properties.

Substantially all of our crude oil and natural gas properties, excluding our share of properties held by the limited partnerships that we sponsor, have been mortgaged or pledged as security for our revolving credit facility.

Facilities

We lease 109,000 square feet of office space in Denver, Colorado, which serves as our corporate office, through February 2023. We own a 32,000 square foot administrative office building located in Bridgeport, West Virginia.

We also lease field operating facilities in or near Evans, Colorado, and Midland, Texas.

Governmental Regulation

The U.S. crude oil and natural gas industry is extensively regulated at the federal, state and local levels. The following is a summary of certain laws, rules and regulations currently in force that apply to us. The regulatory environment in which we operate changes frequently and we cannot predict the timing or nature of such changes or their effects on us.

Regulation of Crude Oil and Natural Gas Exploration and Production. Our exploration and production activities are subject to a variety of rules and regulations concerning drilling permits, location, spacing and density of wells, water discharge and disposal, prevention of waste, bonding requirements, surface use and restoration and well plugging and abandonment. The primary state-level regulatory authority regarding these matters is the Colorado Oil and Gas Conservation Commission (the “COGCC”) in Colorado and the Texas Railroad Commission in Texas. For example, prior to preparing a surface location and commencing drilling operations on a well, we must procure permits and/or approvals for the various stages of the drilling process from the relevant state and local agencies. Similarly, our operations must comply with rules governing the size of drilling and spacing units or proration units and the unitization or pooling of lands and leases. Some states, such as Colorado, allow the forced pooling or integration of tracts to facilitate exploration while other states, such as Texas, rely primarily or exclusively on voluntary pooling of lands and leases.

In states such as Texas, where pooling is primarily or exclusively voluntary, it may be more difficult to form units and therefore to drill and develop our leases in circumstances where we do not own all of the leases in the proposed unit. State laws may also prohibit the venting or flaring of natural gas, which may impact rates of production of crude oil and natural gas from our wells. Leases covering state or federal lands often include additional laws, regulations and conditions which can limit the location, timing and number of wells we can drill and impose other requirements on our operations, all of which can increase our costs.

Regulation of Transportation of Commodities. We move natural gas through pipelines owned by other entities and sell natural gas to other entities that also utilize common carrier pipeline facilities. Natural gas pipeline interstate transmission and storage activities are subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 ("NGA") and under the Natural Gas Policy Act of 1978 ("NGPA"). Rates and charges for the transportation of natural gas in interstate commerce, and the extension, enlargement or abandonment of jurisdictional facilities, among other things, are subject to regulation. Natural gas pipeline companies hold certificates of public convenience and necessity issued by FERC authorizing ownership and operation of certain pipelines, facilities and properties.

In addition to regulation of natural gas pipeline interstate transmission and storage activities, under the Energy Policy Act of 2005 (the “EPAct 2005”), it is unlawful for “any entity” to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or the purchase or sale of transportation services subject to regulation by FERC. The EPAct 2005 provides FERC with substantial enforcement authority to prohibit such manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.
In December 2007, FERC issued Order 704 (as amended by subsequent orders on rehearing, “Order 704”), which requires that any market participant, including natural gas producers, gatherers and marketers, that engaged in wholesale sales or purchases of natural gas that equaled or exceeded 2.2 MMBtus of physical natural gas in the previous calendar year to report to FERC the aggregate volumes of natural gas produced or sold at wholesale in such calendar year. Order 704 applies only to those transactions that utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the market participant to determine which individual transactions are to be reported under the guidance of Order 704. Additional information that must be reported includes whether the price in the relevant transaction was reported to any index publisher, and if so, whether such reporting complied with FERC’s policy statement on price reporting. To the extent that we engage in wholesale sales or purchases of natural gas that equal or exceed 2.2 MMBtus of physical natural gas in the a calendar year pursuant to transactions utilizing, contributing or having the potential to contribute to the formation of price indices, we may be subject to the reporting requirements of Order 704.

Gathering is exempt from regulation under the NGA, thus allowing gatherers to charge negotiated rates. Gathering lines are, however, subject to state regulation, which includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and rate regulation on a complaint basis. We own certain pipeline facilities in the Delaware Basin that we believe are exempt from regulation under the NGA as “gathering facilities,” but which may in some cases be subject to state regulation.

Although FERC has set forth a general test to determine whether facilities are exempt from regulation under the NGA as “gathering” facilities, FERC’s determinations as to the classification of facilities are performed on a case-by-case basis. With respect to facilities owned by third parties and on which we move natural gas, to the extent that FERC subsequently issues an order reclassifying facilities previously thought to be subject to FERC jurisdiction as non-jurisdictional gathering facilities, and depending on the scope of that decision, our costs of moving natural gas to the point of sale may be increased. Further, to the extent that FERC issues an order reclassifying facilities that we own that were previously thought to be non-jurisdictional gathering facilities as subject to FERC jurisdiction, we could be subject to additional regulatory requirements under the NGA and the NGPA.

Transportation and safety of natural gas is also subject to regulation by the U.S. Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration (“PHMSA”), under the Natural Gas Pipeline Safety Act of 1968, as amended, which imposes safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the “PIPES Act 2006”), and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the “PIPES Act 2011”). We own certain pipeline facilities in the Delaware Basin that are subject to such regulation by PHMSA.

In addition to natural gas, we move crude oil, condensate and natural gas liquids (collectively, “liquids”) through pipelines owned by other entities and sell such liquids to other entities that also utilize pipeline facilities that may be subject to regulation by FERC. FERC regulates the rates and terms and conditions of service for the interstate transportation of liquids under the Interstate Commerce Act, as it existed on October 1, 1977 (the “ICA”), and the rules and regulations promulgated thereunder. This includes movements of liquids through any pipelines, including those located solely within one state, that are providing part of the continuous movement of such liquids in interstate commerce for a shipper. The ICA requires that pipelines providing jurisdictional movements maintain a tariff on file with FERC, setting forth established rates and the rules and regulations governing transportation service, which must be “just and reasonable.” The ICA also requires that services be provided in a manner that is not unduly discriminatory or unduly preferential; in some cases, this may result in the proration of capacity among shippers in an equitable manner.

The intrastate transportation of crude oil and NGLs is subject to regulation by state regulatory commissions, which in some cases require the provision of intrastate transportation on a nondiscriminatory basis and the prorationing of capacity on such pipelines under policies set forth in published tariffs. These state-level regulations may also impose certain limitations on the rates that the pipeline owner may charge for transportation.

Transportation and safety of liquids by pipeline is subject to regulation by PHMSA pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as well as the PIPES Act 2006 and the PIPES Act 2011, which govern the design, installation, testing, construction, operation, replacement and management of liquids pipeline facilities. Liquids that are transported by rail may also be subject to additional regulation by PHMSA.

The availability, terms and cost of transportation affect the amounts we receive for our commodities. Historically, producers were able to flow supplies into interstate pipelines on an interruptible basis; however, recently we have seen the increased need to acquire firm transportation on pipelines in order to avoid curtailments or shut-in gas, which could adversely affect cash flows from the affected area.

Environmental Matters

Our operations are subject to numerous laws and regulations relating to environmental protection. These laws and regulations change frequently, and the effect of these changes is often to impose additional costs or other restrictions on our operations. We cannot predict the occurrence, timing, nature or effect of these changes.

Hazardous Substances and Wastes

We generate wastes that may be subject to the Federal Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes. The U.S. Environmental Protection Agency (“EPA”) and various state agencies have adopted requirements that limit the approved disposal methods for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by our operations that are currently exempt from treatment as “hazardous wastes” may in the future be designated as hazardous wastes, and therefore may subject us to more rigorous and costly operating and disposal requirements. In December 2016, the U.S. District Court for the District of Columbia approved a consent decree between the EPA and a coalition of environmental groups. The consent decree requires the EPA to review and determine whether it will revise the RCRA regulations for exploration and production waste to treat such waste as hazardous waste. The EPA must complete its review and make its decision regarding revision by March 2019. If the

EPA chooses to revise the applicable RCRA regulations, it must sign a notice taking final action related to the new regulation by July 2021.

We currently own or lease numerous properties that have been used for the exploration and production of crude oil and natural gas for many years. If hydrocarbons or other wastes have been disposed of or released on or under the properties that we own or lease or on or under locations where such wastes have been taken for disposal by us or prior owners or operators of such properties, we could be subject to liability under the Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), RCRA and analogous state laws, as well as state laws governing the management of crude oil and natural gas wastes. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of, transported or arranged for the disposal of the hazardous substances found at the site. Individuals who are or were responsible for release of hazardous substances under CERCLA may be subject to full liability for the costs of cleaning up the hazardous substances that have been released into the environment or remediation to prevent future contamination and for damages to natural resources. Under state laws, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Hydraulic Fracturing

Hydraulic fracturing is commonly used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. We consistently utilize hydraulic fracturing in our crude oil and natural gas development programs. The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations which are held open by the grains of sand, enabling the crude oil or natural gas to more easily flow to the wellbore. The process is generally subject to regulation by state oil and gas commissions, but is also the subject of various other regulatory initiatives at the federal, state and local levels.

Federal Regulation

Beginning in 2012, the EPA implemented Clean Air Act (“CAA”) standards (New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants) applicable to hydraulically fractured natural gas wells and certain storage vessels. The standards require, among other things, use of reduced emission completions, or “green” completions, to reduce volatile organic compound emissions during well completions as well as new controls applicable to a wide variety of storage tanks and other equipment, including compressors, controllers and dehydrators.

In February 2014, the EPA issued permitting guidance under the Safe Drinking Water Act ("SDWA") for the underground injection of liquids from hydraulically fractured and other wells where diesel is used. Depending upon how it is implemented, this guidance may create duplicative requirements in certain areas, further slow the permitting process in certain areas, increase the costs of operations and result in expanded regulation of hydraulic fracturing activities by the EPA, and may therefore adversely affect even companies, such as us, that do not use diesel fuel in hydraulic fracturing activities.

In May 2014, the EPA issued an advance notice of proposed rulemaking under the Toxic Substances Control Act pursuant to which it will collect extensive information on the chemicals used in hydraulic fracturing fluid, as well as other health-related data, from chemical manufacturers and processors.

The U.S. Department of the Interior, through the Bureau of Land Management (the “BLM”), finalized a rule in 2015 requiring the disclosure of chemicals used, mandating well integrity measures and imposing other requirements relating to hydraulic fracturing on federal lands. The BLM rescinded the rule in December 2017; however, the BLM’s rescission of the rule has been challenged in the United States District Court for the Northern District of California.

In June 2016, the EPA finalized pretreatment standards for indirect discharges of wastewater from the oil and gas extraction industry. The regulation prohibits sending wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works.

In December 2016, the EPA released a report titled “Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources.” The report concluded that activities involved in hydraulic fracturing can have impacts on drinking water under certain circumstances. These and similar studies, depending on their degree of development and nature of results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

In November 2018, the EPA and the non-profit organization known as the State Review of Oil and Natural Gas Environmental Regulations (“STRONGER”) entered into a Memorandum of Understanding pursuant to which the EPA has affirmed its commitment to meaningful participation in STRONGER’s efforts to develop guidelines for state oil and natural gas environmental regulatory programs, conduct reviews of such programs and publish reports of those reviews.

State Regulation

The states in which we currently operate have adopted or are considering adopting laws and regulations that impose or could impose, among other requirements, stringent permitting or air emission control, chemical disclosure, wastewater disposal, baseline sampling, seismic monitoring, well monitoring and materials handling requirements on hydraulic fracturing and/or well construction and well location requirements and more stringent notification or consultation processes that relate to hydraulic fracturing. Similarly, some states, including Texas, have implemented rules requiring the submission of detailed information related to seismicity in connection with injection well permit applications for the disposal of wastewater.

Colorado and Texas require that chemicals used in the hydraulic fracturing of a well be reported in a publicly searchable registry website developed and maintained by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission.

Concerns about hydraulic fracturing have contributed to support for ballot initiatives in Colorado that would dramatically limit the areas of the state in which drilling would be permitted to occur. See Item 1A. Risk Factors-Risks Relating to Our Business and the Industry-Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us.

Local Regulation

Various local and municipal bodies in each of the states in which we operate have sought to impose prohibitions, moratoria and other restrictions on hydraulic fracturing activities. In Colorado, the Colorado Supreme Court ruled in 2016 that the cities of Fort Collins and Longmont did not have the authority to prohibit or impose five-year moratoria on hydraulic fracturing. Ballot initiatives and legislation have previously been proposed but not enacted in Colorado that would vest local governmental authorities with greater control over oil and gas development. If similar proposals are enacted in the future, they could conceivably undo the Colorado Supreme Court’s 2016 rulings and enable local authorities to implement hydraulic fracturing bans or other restrictions. We primarily operate in the rural areas of the core Wattenberg Field in Weld County. In Texas, legislation enacted in 2015 generally prohibits political subdivisions from banning, limiting or otherwise regulating oil and gas operations. See Item 1A. Risk Factors-Risks Relating to Our Business and the Industry-Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us.

Private Lawsuits

Lawsuits have been filed against other operators in several states, including Colorado, alleging contamination of drinking water as a result of hydraulic fracturing activities.

Greenhouse Gases

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 such emissions are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings provide the basis for the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. In June 2010, the EPA began regulating GHG emissions from stationary sources.
In the past, Congress has considered proposed legislation to reduce emissions of GHGs. To date, Congress has not adopted any such significant legislation, but could do so in the future. In addition, many states and regions have taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. In February 2014 and November 2017, Colorado adopted

rules regulating methane emissions from the oil and gas sector.
The Obama administration reached an agreement during the December 2015 United Nations climate change conference in Paris pursuant to which the U.S. initially pledged to make a 26 to 28 percent reduction in its GHG emissions by 2025 against a 2005 baseline and committed to periodically update this pledge every five years starting in 2020 (the "Paris Agreement"). In June 2017, President Trump announced that the U.S. would initiate the formal process to withdraw from the Paris Agreement.

Regulation of methane and other GHG emissions associated with oil and natural gas production could impose significant requirements and costs on our operations.

Air Quality

Our operations are subject to the CAA and comparable state and local requirements. The CAA contains provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and state governments continue to develop regulations to implement these requirements. We may be required to incur certain capital investments in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. See the footnote titled Commitments and Contingencies - Litigation and Legal Items to our consolidated financial statements included elsewhere in this report for further information regarding the Clean Air Act Section 114 Information Request that we received from the EPA.

In June 2016, the EPA implemented new requirements focused on achieving additional methane and volatile organic compound reductions from the oil and natural gas industry. The rules imposed, among other things, new requirements for leak detection and repair, control requirements for oil well completions, replacement of certain pneumatic pumps and controllers and additional control requirements for gathering, boosting and compressor stations. In September 2018, the EPA proposed revisions to the 2016 rules. The proposed amendments address certain technical issues raised in administrative petitions and include proposed changes to, among other things, the frequency of monitoring for fugitive emissions at well sites and compressor stations. Also in 2016, the EPA issued guidelines for reducing volatile organic compound emissions from existing oil and natural gas equipment and processes in ozone non-attainment areas, including the Denver Metro North Front Range Ozone 8-Hour Non-Attainment (“Denver Metro/North Front Range NAA”) area discussed below.

In November 2016, the BLM finalized rules to further regulate venting, flaring and leaks during oil and natural gas production activities on onshore federal and Indian leases. The rules require additional controls and impose new emissions and other standards on certain operations on applicable leases, including committed state or private tracts in a federally approved unit or communitized agreement that drains federal minerals. In September 2018, the BLM published a final rule that revises the 2016 rules. The new rule, among other things, rescinds the 2016 rule requirements related to waste-minimization plans, gas-capture percentages, well drilling, well completion and related operations, pneumatic controllers, pneumatic diaphragm pumps, storage vessels and leak detection and repair. The new rule also revised provisions related to venting and flaring. Environmental groups and the States of California and New Mexico have filed challenges to the 2018 rule in the United States District Court for the Northern District of California.

In 2016, the EPA increased the state of Colorado’s non-attainment ozone classification for the Denver Metro/North Front Range NAA area from “marginal” to “moderate” under the 2008 national ambient air quality standards (“NAAQS”). This increase in non-attainment status triggered significant additional obligations for the state under the CAA and resulted in Colorado adopting new and more stringent air quality control requirements in November 2017 that are applicable to our operations. Ozone measurements in the Denver Metro/North Front Range NAA exceeded the NAAQS during 2018, subjecting it to a further reclassification to “serious.” While the Colorado Department of Public Health and Environment (“CDPHE”) may request an exception or other relief from the reclassification, it appears very likely that the Denver Metro/North Front Range NAA will be reclassified as “serious” by early 2020. A “serious” classification will trigger significant additional obligations for the state under the CAA and could result in new and more stringent air quality control requirements, which may in turn result in significant costs and delays in obtaining necessary permits applicable to our operations.

State-level rules applicable to our operations include regulations imposed by the CDPHE's Air Quality Control Commission, including stringent requirements relating to monitoring, recordkeeping and reporting matters.

Water Quality

The federal Clean Water Act ("CWA") and analogous state laws impose strict controls concerning the discharge of pollutants and fill material, including spills and leaks of crude oil and other substances. The CWA also requires approval and/or permits prior to construction, where construction will disturb wetlands or other waters of the U.S. In June 2015, the EPA and the Army Corps of Engineers (the "Corps") issued a new rule known as the Clean Water Rule clarifying the scope of the EPA's and the Corps' jurisdiction under the Clean Water Act with respect to certain types of waterbodies and classifying these waterbodies as regulated. In February 2018, the EPA issued a rule that delays the applicability of the new definition of the waters of the U.S. until 2020. In August 2018, the U.S. District Court for South Carolina found that the EPA and the Corps failed to comply with the Administrative Procedure Act and struck the 2018 rule that attempted to delay the applicability date of the 2015 Clean Water Rule. Other district courts, however, have issued rulings temporarily enjoining the applicability of the 2015 Clean Water Rule itself. Taken together, the 2015 Clean Water Rule is currently in effect in 23 states, and temporarily stayed in the remaining states, including Colorado and Texas. In those remaining states, the 1986 rule and guidance remain in effect. In December 2018, the EPA and the Corps issued a proposed new rule that would differently revise the definition of "waters of the United States" and essentially replace both the 1986 rule and the 2015 Clean Water Rule. According to the agencies, the proposed new rule is "intended to increase CWA program predictability and consistency by increasing clarity as to the scope of 'waters of the United States' federally regulated under the Act." If finalized, this new definition of "waters of the United States" will likely be challenged and sought to be enjoined in federal court.

In January 2017, the Corps issued revised and renewed streamlined general nationwide permits that are available to satisfy permitting requirements for certain work in streams, wetlands and other waters of the U.S. under Section 404 of the CWA and the Rivers and Harbors Act. The new nationwide permits took effect in March 2017, or when certified by each state, whichever was later. The oil and gas industry broadly utilizes nationwide permits 12, 14 and 39 for the construction, maintenance and repairs of pipelines, roads and drill pads, respectively, and related structures in waters of the U.S. that impact less than a half-acre of waters of the U.S. and meet the other criteria of each nationwide permit.

The CWA also regulates storm water run-off from crude oil and natural gas facilities and requires storm water discharge permits for certain activities. Spill Prevention, Control and Countermeasure ("SPCC") requirements of the CWA require appropriate secondary containment load out controls, piping controls, berms and other measures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon spill, rupture or leak.

Endangered Species

The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act and bald and golden eagles under the Bald and Golden Eagle Protection Act. Some of our operations may be located in areas that are or may be designated as habitats for endangered or threatened species or that may attract migratory birds, bald eagles or golden eagles.

Safety and Spill Prevention

In October 2015, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration proposed to expand its regulations in a number of ways, including increased regulation of gathering lines, even in rural areas, and proposed additional standards to revise safety regulations applicable to onshore gas transmission and gathering pipelines in 2016.

Crude oil production is subject to many of the same operating hazards and environmental concerns as natural gas production, but is also subject to the risk of crude oil spills. In addition to SPCC requirements, the Oil Pollution Act of 1990 ("OPA") subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from crude oil spills. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Historically, we have not experienced any significant crude oil discharge or crude oil spill problems.
In May 2015, the U.S. Department of Transportation issued a final rule regarding the safe transportation of flammable liquids by rail. The final rule imposes certain requirements on "offerors" of crude oil, including sampling, testing and certification requirements.
In February 2018, the COGCC comprehensively amended its regulations for oil, gas, and water flowlines to expand requirements addressing flowline registration and safety, integrity management, leak detection, and other matters. The COGCC has also adopted or amended numerous other rules in recent years, including rules relating to safety, flood protection and spill reporting.

We are also subject to rules regarding worker safety and similar matters promulgated by the U.S. Occupational Safety and Health Administration ("OSHA") and other governmental authorities. OSHA has established workplace safety standards that provide guidelines for maintaining a safe workplace in light of potential hazards, such as employee exposure to hazardous substances. To this end, OSHA adopted a new rule governing employee exposure to silica, including during hydraulic fracturing activities, in March 2016.

Employees

As of December 31, 2018, we had approximately 600 full-time employees. Our employees are not covered by collective bargaining agreements. We consider relations with our employees to be good.

WHERE YOU CAN FIND ADDITIONAL INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available free of charge from our website at www.pdce.com as soon as reasonably practicable after such material is filed with, or furnished to, the SEC. We also make available free of charge any of our SEC filings by mail. For a mailed copy of a report, please contact PDC Energy, Inc., Investor Relations, 1775 Sherman Street, Suite 3000, Denver, CO 80203, or call (303) 860-5800.

We recommend that you view our website for additional information, as we routinely post information that we believe is important for investors. Our website can be used to access such information as our recent news releases, committee charters, code of business conduct and ethics, stockholder communication policy, director nomination procedures and our whistle blower hotline. While we recommend that you view our website, the information available on our website is not part of this report and is not incorporated by reference.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock or other securities.

Risks Relating to Our Business and the Industry

Crude oil, natural gas and NGL prices fluctuate and declines in these prices, or an extended period of low prices, can significantly affect the value of our assets and our financial results and may impede our growth.

Our revenue, profitability, cash flows and liquidity depend in large part upon the prices we receive for our crude oil, natural gas and NGLs. Changes in prices affect many aspects of our business, including:
- our revenue, profitability and cash flows;
- our liquidity;
- the quantity and present value of our reserves;
- the borrowing base under our revolving credit facility and access to other sources of capital; and
- the nature and scale of our operations.

The markets for crude oil, natural gas and NGLs are often volatile, and prices may fluctuate in response to, among other things:
- relatively minor changes in regional, national or global supply and demand;
- regional, national or global economic conditions, and perceived trends in those conditions;
- geopolitical factors, such as events that may reduce or increase production from particular oil-producing regions and/or from members of the Organization of Petroleum Exporting Countries ("OPEC"); and
- regulatory changes.

The price of oil has been volatile since mid-2014, with a high over $100 per barrel in June 2014 to lows below $30 per barrel in 2016, in each case based on WTI prices, due to a combination of factors including increased U.S. supply and global economic concerns. In 2018, oil prices ranged from highs of over $70 per barrel to lows of less than $50 per barrel. Prices for natural gas and NGLs have also experienced substantial volatility. If we reduce our capital expenditures due to low prices, natural declines in production from our wells will likely result in reduced production and therefore reduced cash flow from operations, which would in turn further limit our ability to make the capital expenditures necessary to replace our reserves and production.
In addition to factors affecting the price of crude oil, natural gas and NGLs generally, the prices we receive for our production are affected by factors specific to us and to the local markets where the production occurs. The prices that we receive for our production are generally lower than the relevant benchmark prices that are used for calculating commodity derivative positions. These differences, or differentials, are difficult to predict and may widen or narrow in the future based on market forces. Differentials can be influenced by, among other things, local or regional supply and demand factors and the terms of our sales contracts. Over the longer term, differentials will be significantly affected by factors such as investment decisions made by providers of midstream facilities and services, refineries and other industry participants and the overall regulatory and economic climate. For example, increases in U.S. domestic oil production generally, or in production from particular basins, may result in widening differentials. We may be materially and adversely impacted by widening differentials on our production and decreasing commodity prices.

The marketability of our production is dependent upon transportation and processing facilities, the capacity and operation of which we do not control. Market conditions or operational impediments affecting midstream facilities and services could hinder our access to crude oil, natural gas and NGL markets, increase our costs or delay production. Our efforts to address midstream issues may not be successful.

Our ability to market our production depends in substantial part on the availability, proximity and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. If adequate midstream facilities and services are not available to us on a timely basis and at acceptable costs, our production and results of operations will be adversely affected. For example, in recent periods, due to ongoing drilling activities by us and third parties and seasonal changes in temperatures, our principal third-party provider in the Wattenberg Field for midstream facilities and services has experienced significantly increased gathering system pressures. The resulting capacity constraints have restricted our production in the area and reduced our revenue. Similarly, rapid production growth in the Permian Basin has strained the

available midstream infrastructure there with adverse effects on our operations. The use of alternative forms of transportation for oil production, such as trucks or rail, involves risks, including the risk that increased regulation could lead to increased costs or shortages of trucks or rail-cars. In addition to causing production curtailments, capacity constraints can also reduce the price we receive for the crude oil, natural gas and NGLs we produce.
We rely on third parties to continue to construct additional midstream facilities and related infrastructure to accommodate our growth, and the ability and willingness of those parties to do so is subject to a variety of risks. For example:

- Decreases in commodity prices in recent years have resulted in reduced investment in midstream facilities by some third parties;
- Various interest groups have protested the construction of new pipelines, and particularly pipelines near water bodies, in various places throughout the country, and protests have at times physically interrupted pipeline construction activities;
- Some upstream energy companies have sought to reject volume commitment agreements with midstream providers in bankruptcy proceedings, and the risk that such efforts will succeed, or that upstream energy company counterparties will otherwise be unable or unwilling to satisfy their volume commitments, may have the effect of reducing investment in midstream infrastructure; and
- The possibility that new or amended regulations, including regulations that increase mandatory setbacks or enhance local control of oil and gas development, could result in severely curtailed drilling activities in Colorado may discourage investment in midstream facilities.

Like other producers, we from time to time enter into volume commitments with midstream providers in order to induce them to provide increased capacity. If our production falls below the level required under these agreements, we could be subject to substantial penalties. We are currently not producing sufficient volumes to satisfy a volume commitment in the Delaware Basin; although at current commodity prices we have been able to profitably satisfy our obligations under the agreement with volumes purchased from third parties, this may not continue to be the case.

We have pursued a variety of strategies to alleviate some of the risks associated with the midstream services and facilities upon which we rely, including entering into facility expansion agreements with our primary midstream provider in the Wattenberg Field in 2017 and 2018. There can be no assurance that the strategies we pursue will be successful or adequate to meet our needs. For example, while we expect the midstream provider to commence operation of a new facility in the second quarter of 2019, it is not obligated to do so and it may delay or cancel the project entirely. In addition, the benefits to us of that facility may be less than we expect.

Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us.

The regulatory environment in which we operate changes frequently, often through the imposition of new or more stringent environmental and other requirements. We cannot predict the nature, timing or effect of such additional requirements, but they may have a variety of adverse effects on us. The types of regulatory changes that could impact our operations vary widely and include, but are not limited to, the following:

- From time to time ballot initiatives have been proposed in Colorado that would adversely affect our operations. For example, Proposition 112, which was included on the ballot for the November 2018 election in Colorado but was defeated at the polls, would have amended the Colorado Oil and Gas Conservation Act to, among other things, require all new oil and gas development not on federal land to be located at least 2,500 feet away from any occupied structure or broadly defined “vulnerable area”. If enacted, Proposition 112 would have effectively prohibited the vast majority of our planned future drilling activities in Colorado and would therefore have made it impossible to pursue our current development plans. Despite the defeat of Proposition 112, it is likely that similar proposals to increase setbacks, or other proposals to enhance local control of oil and gas development or otherwise restrict our ability to operate or increase our costs, will be made in future years, either by ballot initiative or by legislation. Similar proposals may also be made in other states.

- Substantially all of our drilling activities involve the use of hydraulic fracturing, and proposals are made from time to time at the federal, state and local levels to further regulate, or to ban, hydraulic fracturing practices. Additional laws or regulations regarding hydraulic fracturing could, among other things, increase our costs, reduce our inventory of economically viable drilling locations and reduce our reserves.
- Federal and various state, local and regional governmental authorities have implemented, or considered implementing, regulations that seek to limit or discourage the emission of carbon, methane and other greenhouse gases ("GHGs"). For example, the EPA has made findings and issued regulations that require us to establish and

report an inventory of greenhouse gas emissions, and the state of Colorado has adopted rules regulating methane emissions from oil and gas operations. In addition, the Obama administration reached an agreement during the December 2015 United Nations climate change conference in Paris pursuant to which the U.S. initially pledged to make a 26 percent to 28 percent reduction in its GHG emissions by 2025 against a 2005 baseline (although President Trump subsequently announced that the U.S. is withdrawing from the Paris Agreement). Additional laws or regulations intended to restrict the emission of GHGs could require us to incur additional operating costs and could adversely affect demand for the oil, natural gas and NGLs that we sell. These new laws or rules could, among other things, require us to install new emission controls on our equipment and facilities, acquire allowances to authorize our GHG emissions, pay taxes related to our emissions and administer and manage a GHG emissions program. In addition, like other energy companies, we could be named as a defendant in GHG-related lawsuits.

- Proposals are made from time to time to amend U.S. federal and state tax laws in ways that would be adverse to us, including by eliminating certain key U.S. federal income tax preferences currently available with respect to crude oil and natural gas exploration and production. The changes could include (i) the repeal of the percentage depletion deduction for crude oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Also, state severance taxes may increase in the states in which we operate. This could adversely affect our existing operations in the relevant state and the economic viability of future drilling.
- The development of new environmental initiatives or regulations related to the acquisition, withdrawal, storage and use of surface water or groundwater or treatment and discharge of water waste, may limit our ability to use techniques such as hydraulic fracturing, increase our development and operating costs and cause delays, interruptions or termination of our operations, any of which could have an adverse effect on our operations and financial condition.

See Items 1 and 2, Business and Properties - Governmental Regulation for a summary of certain laws and regulations that currently apply to us. Any of such laws and regulations could be amended, and new laws or regulations could be implemented, in a way that adversely affects our operations.

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in substantial lease renewal costs or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.
Unless production is established within the spacing units covering our undeveloped acreage, our leases for such acreage will expire. The cost to renew such leases may increase significantly and we may not be able to renew such leases on commercially reasonable terms or at all. In 2019, we expect that we will allow 35 percent of our net leaseholds in the Delaware Basin to expire based on our current drilling plan, and we incurred an impairment charge in the fourth quarter of 2018 relating to these anticipated expirations. Unexpected lease expirations could also occur if our actual drilling activities differ materially from our current expectations, and this could result in further impairment charges. The risk of lease expiration is greater at times and in areas where the pace of our exploration and development activity slows. Our ability to drill and develop the locations necessary to maintain our leases depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors.

A substantial part of our crude oil, natural gas and NGLs production is located in the Wattenberg Field, making us vulnerable to risks associated with operating primarily in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing formations.
Although we have significant leasehold positions in the Delaware Basin in Texas, our current production is primarily located in the Wattenberg Field in Colorado. Because our production is not as diversified geographically as many of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of

any regional events, including:

- fluctuations in prices of crude oil, natural gas and NGLs produced from the wells in the area;
- natural disasters such as the flooding that occurred in northern Colorado in September 2013;
- restrictive governmental regulations; and
- curtailment of production or interruption in the availability of gathering, processing or transportation infrastructure and services and any resulting delays or interruptions of production from existing or planned new wells.

For example, bottlenecks in processing and transportation that have occurred in some recent periods in the Wattenberg Field have negatively affected our results of operations, and these adverse effects may be disproportionately severe to us compared to our more geographically diverse competitors. Similarly, the concentration of our producing assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules that could adversely affect development activities or production relating to those formations. Such an event could have a material adverse effect on our results of operations and financial condition. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the Wattenberg Field and the Delaware Basin, the demand for, and cost of, drilling rigs, equipment, supplies, chemicals, personnel and oilfield services often increase as well. Shortages or the high cost of drilling rigs, equipment, supplies, chemicals, personnel or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital forecast, which could have a material adverse effect on our business, financial condition or results of operations.

Certain of our properties are subject to land use restrictions, which could limit the manner in which we conduct our business.

Certain of our properties are subject to land use restrictions, including city ordinances, which could limit the manner in which we conduct our business. Such restrictions could affect, among other things, our access to and the permissible uses of our facilities as well as the manner in which we produce oil and natural gas, and may restrict or prohibit drilling in general. The costs we incur to comply with such restrictions may be significant, and we may experience delays or curtailment in the pursuit of development activities and may be precluded from drilling wells in some areas.

We may incur losses as a result of title defects in the properties in which we invest or acquire.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform record title examinations before we acquire oil and gas leases and related interests. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We are subject to complex federal, state, local and other laws and regulations that adversely affect the cost and manner of doing business.

Our exploration, development, production and marketing operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning crude oil and natural gas wells and associated facilities. Under these laws and regulations, we could also be liable for personal injuries, property damage and natural resource or other damages, and could be required to change, suspend or terminate operations. Similar to our competitors, we incur substantial operating and capital costs to comply with such laws and regulations. These costs may put us at a competitive disadvantage compared to larger companies in the industry which can more easily capture economies of scale with respect to compliance. A summary of certain laws and regulations that apply to us is set forth in Items 1 and 2 - Business and Properties - Governmental Regulation.

In June 2017, the U.S. Department of Justice, on behalf of the EPA and the State of Colorado, filed a complaint against us, claiming that we failed to operate and maintain certain condensate collection equipment at 65 facilities so as to minimize leakage of volatile organic compounds in compliance with applicable law. In October 2017, we entered into a consent decree to resolve the lawsuit. Pursuant to the consent decree, we agreed to implement a variety of operational enhancements and mitigation and similar projects, including vapor control system modifications and verification, increased inspection and monitoring and installation of tank pressure monitors. If we materially fail to comply with the requirements of the consent decree with respect to those matters, we could be subject to additional liability. See the footnote titled Commitments and Contingencies - Litigation and Legal Items to our consolidated financial statements included elsewhere in this report for further information regarding this litigation.

A major risk inherent in our drilling plans is the possibility that we will be unable to obtain needed drilling permits from relevant governmental authorities in a timely manner. Our ability to obtain the permits needed to pursue our development plans may be impacted by a variety of factors, including opposition by landowners or interest groups. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable or unexpected conditions or costs could have a material adverse effect on our ability to explore or develop our properties.

Our ability to produce crude oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of or recycle the water we use at a reasonable cost, in a timely manner and within applicable environmental rules.

Drilling and development activities such as hydraulic fracturing require the use of water and result in the production of wastewater. Our operations could be adversely impacted if we are unable to locate sufficient amounts of water or dispose of or recycle water used in our exploration and production operations. The quantity of water required in certain completion operations, such as hydraulic fracturing, and changing regulations governing usage may lead to water constraints, supply concerns and regulatory issues, particularly in relatively arid climates such as eastern Colorado and western Texas. For example, increased drilling activity in the Delaware Basin in recent years has led to heightened concerns about water supply issues in the area and this may lead to regulatory actions, including rules providing local governments greater authority over water use, that adversely impact our operations.

Our operations depend on being able to reuse or dispose of wastewater in a timely and economic fashion. Wastewater from oil and gas operations is often disposed of through underground injection. Wells in the Delaware Basin typically produce relatively large amounts of water that require disposal and an increased number of earthquakes have been detected in the Delaware Basin in recent years. Some studies have linked earthquakes, or induced seismicity, in certain areas to underground injection, which is leading to increased public and regulatory scrutiny of injection safety.

Reduced commodity prices could result in significant impairment charges and significant downward revisions of proved reserves.
Commodity prices are volatile. Significant and rapid declines in prices have occurred in the past and may occur in the future. Low commodity prices could result in, among other things, significant impairment charges. The cash flow model we use to assess properties for impairment includes numerous assumptions, such as management’s estimates of future oil and gas production and commodity prices, the outlook for forward commodity prices and operating and development costs. All inputs to the cash flow model must be evaluated at each date the estimate of future cash flows for each producing basin is calculated. However, a significant decrease in long-term forward prices alone could result in a significant impairment for our properties that are sensitive to declines in prices. We have incurred impairment charges in a number of recent periods, including charges of $458.4 million and $285.9 million in 2018 and 2017, respectively, to write down assets and $75.1 million to impair goodwill associated with our acquisition in the Delaware Basin in 2017. Similar charges could occur in the future.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.
Calculating reserves for crude oil, natural gas and NGLs requires subjective estimates of remaining volumes of underground accumulations of hydrocarbons. Assumptions are also made concerning commodity prices, production levels and operating and development costs over the economic life of the properties. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be inaccurate. Independent petroleum engineers prepare our estimates of crude oil, natural gas and NGLs reserves using pricing, production, cost, tax and other information that we provide. The reserve estimates are based on assumptions regarding commodity prices, production levels and operating and development costs that may prove to be incorrect. Any significant variance from these assumptions to actual results could greatly affect:

- the economically recoverable quantities of crude oil, natural gas and NGLs attributable to any particular group of properties;
- future depreciation, depletion and amortization (“DD&A”) rates and amounts;

- impairments in the value of our assets;
- the classifications of reserves based on risk of recovery;
- estimates of future net cash flows;
- timing of our capital expenditures; and
- the amount of funds available for us to borrow under our revolving credit facility.

Some of our reserve estimates must be made with limited production histories, which renders these estimates less reliable than those based on longer production histories. Further, reserve estimates are based on the volumes of crude oil, natural gas and NGLs that are anticipated to be economically recoverable from a given date forward based on economic conditions that exist at that date. The actual quantities of crude oil, natural gas and NGLs recovered will be different than the reserve estimates since they will not be produced under the same economic conditions as are used for the reserve calculations.

In addition, quantities of probable and possible reserves by definition are inherently more risky than proved reserves, in part because they have greater uncertainty associated with the recoverable quantities of hydrocarbons.

At December 31, 2018, approximately 67 percent of our estimated proved reserves were undeveloped. These reserve estimates reflect our plans to make significant capital expenditures to convert our PUDs into proved developed reserves, including approximately $4.4 billion during the five years ending December 31, 2023, as estimated in the calculation of the standardized measure of oil and gas activity. The estimated development costs may not be accurate, development may not occur as scheduled and results may not be as estimated. If we choose not to develop PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC’s reserve reporting rules, PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of initial booking, and we may therefore be required to downgrade any PUDs that are not developed within this five-year time frame.

The present value of the estimated future net cash flows from our proved reserves is not necessarily the same as the current market value of those reserves. Pursuant to SEC rules, the estimated discounted future net cash flows from our proved reserves, and the estimated quantity of those reserves, are based on the prior year’s first day of the month 12-month average crude oil and natural gas index prices. However, factors such as actual prices we receive for crude oil and natural gas and hedging instruments, the amount and timing of actual production, the amount and timing of future development costs, the supply of and demand for crude oil, natural gas and NGLs and changes in governmental regulations or taxation, also affect our actual future net cash flows from our properties. The timing of both our production and incurrence of expenses in connection with the development and production of crude oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10 percent discount factor we use when calculating discounted future net cash flows (the rate required by the SEC) may not be the most appropriate discount factor based on interest rates currently in effect and risks associated with our properties or the industry in general.

Unless reserves are replaced as they are produced, our reserves and production will decline, which would adversely affect our future business, financial condition and results of operations. We may not be able to develop our identified drilling locations as planned.

Producing crude oil, natural gas and NGL reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline may change over time and may exceed our estimates. Our future reserves and production and, therefore, our cash flows and income, are highly dependent on our ability to efficiently develop and exploit our current reserves and to economically find or acquire additional recoverable reserves. We may not be able to develop, discover, or acquire additional reserves to replace our current and future production at acceptable costs. Our failure to do so would adversely affect our future operations, financial condition and results of operations.

We have identified a number of well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including:

- crude oil, natural gas and NGL prices;
- the availability and cost of capital;
- drilling and production costs;
- availability of drilling services and equipment;
- drilling results;
- lease expirations or limitations as to depth;
- midstream constraints;
- access to and availability of water sourcing and distribution systems;
- regulatory approvals; and
- other factors.

Because of these factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce crude oil, natural gas or NGLs from these or any other potential well locations. In addition, the number of drilling locations available to us will depend in part on the spacing of wells in our operating areas. An increase in well density in an area could result in additional locations in that area, but a reduced production performance from the area on a per-well basis. Further, certain of the horizontal wells we intend to drill in the future may require pooling of our lease interests with the interests of third parties. Some states, including Colorado, allow the involuntary pooling of tracts in a relatively broad number of circumstances in order to facilitate exploration. Other states, notably Texas, restrict involuntary pooling to a much narrower set of circumstances and consequently these states rely primarily on voluntary pooling of lands and leases. In states such as Texas where pooling is accomplished primarily on a voluntary basis, it may be more difficult to form units and, therefore, more difficult to fully develop a project if we own less than all the leasehold in the proposed units or one or more of our leases in the proposed units does not provide the necessary pooling authority. If third parties in the proposed units are unwilling to pool their interests with ours, we may be unable to require such pooling on a timely basis or at all, which would limit the total horizontal wells we can drill. Further, the number of available locations will depend in part on the expected lateral lengths of the horizontal wells we drill. Because the intended lateral length of a horizontal well is subject to change for a variety of reasons, our estimated drilling locations will change over time. For this or numerous other reasons, our actual drilling activities may materially differ from those presently identified.

Our inventory of drilling projects includes locations in addition to those that we currently classify as proved, probable and possible. The development of and results from these additional projects are more uncertain than those relating to probable and possible locations, and significantly more uncertain than those relating to proved locations. We have generally accelerated the pace of our development activities in the Wattenberg Field over the past several years, and this has reduced our related inventory of drilling locations. In addition, our Wattenberg Field inventory was further reduced by recent acreage exchange transactions in which we received, among other things, increased working interests in certain locations in exchange for our right to develop other locations. We anticipate that our remaining locations in the field will not, on average, be as productive as economic as many those we have drilled in recent years, due to lower anticipated overall production or higher gas-to-oil ratios. In the Delaware Basin, our inventory is subject to, among other things, lease expiration issues and our continued analysis of geologic issues in certain areas.

The wells we drill may not yield crude oil, natural gas or NGLs in commercially viable quantities and productive wells may be less successful than we expect.

A prospect is a property on which our geologists have identified what they believe, based on available information, to be indications of hydrocarbon-bearing rocks. However, given the limitations of available data and technology, our geologists cannot know conclusively prior to drilling and testing whether crude oil, natural gas or NGLs will be present in sufficient quantities to repay drilling or completion costs and generate a profit. Furthermore, even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques do not enable our geologists to be certain as to the quantity of the hydrocarbons in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and testing expenses as a result of such expenditures, which may result in a reduction in our returns or losses. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. If a well is determined to be dry or uneconomic, which can occur even though it contains some crude oil, natural gas or NGLs, it is classified as a dry hole and must be plugged and abandoned in accordance with applicable regulations. This generally results in the loss of the entire cost of drilling and completion to that point, the cost of plugging and lease costs associated with the prospect. Even wells that are completed and placed into production may not produce sufficient crude oil, natural gas and NGLs to be profitable, or they may be less productive and/or profitable than we expected. For example, the data we use to model anticipated results from wells in a particular area may prove to be not representative of actual results from typical wells in the area, and this could result in production that falls short of estimates reflected in our internal business plans and/or guidance, "type curve" or other disclosures we make to the public. This risk is higher for us in certain areas in the Delaware Basin that have relatively complex geological characteristics and correspondingly greater variability in well results. If we drill a dry hole or unprofitable well on a current or future prospect, or if drilling or completion costs increase, the profitability of our operations will decline and the value of our properties will likely be reduced. Exploratory drilling is typically subject to substantially greater risk than development drilling. In addition, initial results from a well are not necessarily indicative of its performance over a longer period.

Drilling for and producing crude oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

Drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling can be unprofitable, not only due to dry holes, but also due to curtailments, delays or cancellations as a result of other factors, including:

- unusual or unexpected geological formations;
- pressures;
- fires;
- floods;
- loss of well control;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delays in the delivery of equipment and services;
- unanticipated environmental liabilities;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and regulatory penalties. For example, a loss of containment of hydrocarbons during drilling activities could potentially subject us to civil and/or criminal liability and the possibility of substantial costs, including for environmental remediation. We maintain insurance against various losses and liabilities arising from our operations; however, insurance against certain operational risks may not be available or may be prohibitively expensive relative to the perceived risks presented. For example, we may not have coverage with respect to a pollution event if we are unaware of the event while it is occurring and are therefore unable to report the occurrence of the event to our insurance company within the time frame required under our insurance policy. Thus, losses could occur for uninsurable or uninsured risks or for amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance and/or governmental or third party responses to an event could have a material adverse effect on our business activities, financial condition and results of operations. We are currently involved in various remedial and investigatory activities at some of our wells and related sites.
In addition, certain technical risks relating to the drilling of horizontal wells - including those relating to our ability to fracture stimulate the planned number of stages and to successfully run casing the length of the well bore - have increased in recent years because we have increased the average lateral length of the horizontal wells we drill. Longer-lateral wells are also typically more expensive and require more time for preparation. In addition, we have transitioned to the use of multi-well pads instead of single-well sites. The use of multi-well pad drilling increases some operational risks because problems affecting the pad or a single well could adversely affect production from all of the wells on the pad. Pad drilling can also make our overall production, and therefore our revenue and cash flows, more volatile, because production from multiple wells on a pad will typically commence simultaneously. While we believe that we will be better served by using multi-well pads with longer lateral wells, the risk component involved in such drilling will be increased in some respects, with the result that we might find it more difficult to achieve economic success in our drilling program.

The inability of one or more of our customers or other counterparties to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from our crude oil, natural gas and NGLs sales or joint interest billings to a small number of third parties in the energy industry. This concentration of customers and joint interest owners may affect our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our commodity derivatives expose us to credit risk in the event of nonperformance by counterparties. Nonperformance by our customers or derivative counterparties may adversely affect our financial condition and profitability. We face similar risks with respect to our other counterparties, including the lenders under our revolving credit facility and the providers of our insurance coverage.

Seasonal weather conditions and lease stipulations can adversely affect our operations.

Seasonal weather conditions and lease stipulations designed to prohibit or limit operations during crop-growing seasons and to protect wildlife affect operations in some areas. In certain areas drilling and other activities may be restricted or prohibited by lease stipulations, or prevented by weather conditions, for significant periods of time. This limits our operations in those areas and can intensify competition during the active months for drilling rigs, equipment, supplies, chemicals, personnel, and oilfield services, which may lead to additional or increased costs or periodic shortages. These constraints, and the resulting high costs or shortages, could delay our operations and materially increase operating and capital costs and therefore adversely affect our profitability. Similarly, extreme temperatures during some recent periods adversely impacted the operation of certain midstream facilities, and therefore our production. Similar events could occur in the future and could negatively impact our results of operations and cash flows.

We have limited control over activities on properties in which we own an interest but we do not operate, which could reduce our production and revenues.

We operate approximately 84 percent of the wells in which we own an interest. If we do not operate a property, we do not have control over normal operating procedures, expenditures or future development of the property. The success and timing of drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator’s timing and amount of capital expenditures, expertise (including safety and environmental compliance) and financial resources, inclusion of other participants in drilling wells and use of technology. The failure of an operator to conduct drilling activities properly, or its breach of the applicable agreements, could reduce production and revenues and adversely affect our profitability. These risks may be heightened during periods of depressed commodity prices as operators may propose activities that we believe to be economically unattractive, leading us to incur non-consent penalties. Our lack of control over non-operated properties also makes it more difficult for us to forecast capital expenditures, production and related matters.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

We frequently own less than all of the working interest in the oil and gas leases on which we conduct operations. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities, arising from the actions of the other owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, may declare bankruptcy. In the event any of our project partners does not pay its share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover the costs from the partner. This could materially adversely affect our financial position.

We may not be able to keep pace with technological developments in our industry.

Our industry is characterized by rapid and significant technological advancements. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those or other new technologies at substantial cost. In addition, our 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. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we were unable to use the most advanced technology, our business, financial condition and results of operations could be materially adversely affected.

Competition in our industry is intense, which may adversely affect our ability to succeed.

Our industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce crude oil, natural gas and NGLs, 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 properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, larger companies may have a greater ability to continue exploration activities during periods of low commodity prices. Larger competitors may also be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which could adversely affect our competitive position. These factors could adversely affect our operations and our profitability.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel.

Our future success depends to a large extent on the services of our key employees. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

A failure to complete successful acquisitions would limit our growth.

Because our crude oil and natural gas properties are depleting assets, our future reserves, production volumes and cash flows depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. In addition, we continue to strive to achieve greater efficiencies in our drilling program, and our ability to do so is dependent in part on our ability to complete asset exchanges and other acquisitions that allow us to increase our working interests in particular properties. When attractive opportunities arise, acquiring additional crude oil and natural gas properties, or businesses that own or operate such properties, is a significant component of our strategy. We may not be able to identify attractive acquisition opportunities. If we do identify an appropriate acquisition candidate, we may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. It may be difficult to agree on the economic terms of a transaction, as a potential seller may be unwilling to accept a price that we believe to be appropriately reflective of prevailing economic conditions. If we are unable to complete suitable acquisitions, it will be more difficult to replace our reserves, and an inability to replace our reserves would have a material adverse effect on our financial condition and results of operations.

Acquisitions of properties are subject to the uncertainties of evaluating recoverable reserves and potential liabilities, including environmental uncertainties.

Acquisitions of producing and undeveloped properties have been an important part of our growth over time. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, development potential, future commodity prices, operating costs, title issues and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we generally perform engineering, environmental, geological and geophysical reviews of the acquired properties that we believe are generally consistent with customary industry practices. However, such reviews are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well prior to an acquisition and our ability to evaluate undeveloped acreage is inherently imprecise. Even when we inspect a well, we may not always discover structural, subsurface and environmental problems that may exist or arise. In some cases, our review prior to signing a definitive purchase agreement may be even more limited. In addition, we often acquire acreage without any warranty of title except as to claims made by, through or under the transferor.

When we acquire properties, we will generally have potential exposure to liabilities and costs for environmental and other problems existing on the acquired properties, and these liabilities may exceed our estimates. We may not be entitled to contractual indemnification associated with acquired properties. We often acquire interests in properties on an “as is” basis with no or limited remedies for breaches of representations and warranties. Therefore, we could incur significant unknown liabilities, including environmental liabilities or losses due to title defects, in connection with acquisitions for which we have limited or no contractual remedies or insurance coverage. In addition, the acquisition of undeveloped acreage is subject to many inherent risks and we may not be able to realize efficiently, or at all, the assumed or expected economic benefits of acreage that we acquire.

Additionally, significant acquisitions can change the nature of our operations depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or may be in different geographic locations than our existing properties. These factors can increase the risks associated with an acquisition. Acquisitions also present risks associated with the additional indebtedness that may be required to finance the purchase price and any related increase in interest expense or other related charges.

Some of our acquisitions are structured as asset trades or exchanges. These transactions may give rise to any or all of the foregoing risks. In addition, transactions of this type create a risk that we will undervalue the properties we transfer to the counterparty in the trade or exchange or overvalue the properties we receive. Such an undervaluation or overvaluation would result in the transaction being less favorable to us than we expected.

Complications with the design or implementation of our new enterprise resource planning system could adversely impact our business and operations.

We rely extensively on information systems and technology to manage our business and summarize operating results. We are in the process of implementing a new ERP system. This ERP system will replace our existing operating and financial systems. The ERP system is designed to enhance the maintenance of our financial records, improve operational functionality and provide timely information to our management team related to the operation of the business. The ERP system implementation process has required, and will continue to require, the investment of significant personnel and financial resources. We may not be able to successfully implement the ERP system without experiencing delays, increased costs and other difficulties. If we are unable to successfully design and implement the new ERP system as planned, our financial position, results of operations and cash flows could be negatively impacted. Additionally, if we do not effectively implement the ERP system as planned or the ERP system does not operate as intended, the effectiveness of our internal control over financial reporting could be adversely affected or our ability to assess those controls adequately could be delayed.

We operate in a litigious environment. The cost of defending any suits brought against us, and any judgments or settlements resulting from such suits, could have an adverse effect on our results of operations and financial condition.

Like many oil and gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, employment litigation, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of our business. For example, in recent years, we have been subject to lawsuits regarding royalty practices and payments and matters relating to certain of our affiliated partnerships. As discussed in the footnote titled Commitments and Contingencies to our consolidated financial statements included elsewhere in this report, we are the subject of a recently filed lawsuit relating to our two remaining affiliated partnerships and are currently involved in a fiduciary duty lawsuit regarding our environmental compliance programs. The outcome of legal proceedings is inherently uncertain. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management attention and other factors. In addition, the resolution of such a proceeding could result in penalties or sanctions, settlement costs and/or judgments, consent decrees or orders requiring a change in our business practices, any of which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties, sanctions or costs may be insufficient. Judgments and estimates to determine accruals or the anticipated range of potential losses related to legal and other proceedings could change from one period to the next, and such changes could be material. Information regarding our legal proceedings can found in the footnote titled Commitments and Contingencies - Litigation and Legal Items to our consolidated financial statements included elsewhere in this report.

Our business could be negatively impacted by security threats, including cybersecurity threats and other disruptions.

We face various security threats, including attempts by third parties to gain unauthorized access to competitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. There can be no assurance that the procedures and controls we use to monitor these threats and mitigate our exposure to them will be sufficient to prevent them from materializing.

Our industry has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain exploration, development and production activities. We depend on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to store, transmit, process and record sensitive information (including but not limited to trade secrets, employee information and financial and operating data), communicate with our employees and business partners, and for many other activities related to our business. In addition, computer systems control the oil and gas production and processing equipment that are necessary to deliver our production to market. A disruption or failure of these systems, or of the networks and infrastructure on which they rely, may cause damage to critical production, distribution and/or storage assets, delay or prevent delivery to markets, or make it difficult to accurately account for production and settle transactions.

As dependence on digital technologies has increased in our industry, cyber incidents, including deliberate attacks and unintentional events, have also increased. Our systems and infrastructure are subject to damage or interruption from a number of potential sources including natural disasters, software viruses or other malware, power failures, cyber-attacks and other events. We also face various other cyber-security threats from criminal hackers, state-sponsored intrusion, industrial espionage and employee malfeasance, including threats to gain access to sensitive information or to render data or systems unusable.

Our business partners, including vendors, service providers, operating partners, purchasers of our production and financial institutions, are also dependent on digital technology. A vulnerability in the cybersecurity of one or more of our vendors could facilitate an attack on our systems.

Our technologies, systems and networks, and those of our business partners, may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, theft of property or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Although we have not suffered material losses related to cyber-attacks to date, if we were successfully attacked, we could incur substantial remediation and other costs or suffer other negative consequences, such as a loss of competitive information, critical infrastructure, personnel or capabilities essential to our operations. Events of this nature could have a material adverse effect on our reputation, financial condition, results of operations or cash flows. Moreover, as the sophistication of cyber-attacks continues to evolve, we may be required to expend significant additional resources to further enhance our digital security or to remediate vulnerabilities.
The physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

Many scientists believe that increasing concentrations of carbon dioxide, methane and other GHGs in the Earth's atmosphere are changing global climate patterns. One consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. Flooding that occurred in Colorado in 2013 is an example of an extreme weather event that negatively impacted our operations. If such events were to continue to occur, or become more frequent, our operations could be adversely affected in various ways, including through damage to our facilities or from increased costs for insurance.

Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term “global warming” as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our production could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

Risks Relating to Financial Matters

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our production and reserves, and ultimately our profitability.
Our industry is capital intensive. We expect to continue to make substantial capital expenditures for the exploration, development, production and acquisition of crude oil, natural gas and NGL reserves. To date, we have financed capital expenditures primarily with bank borrowings under our revolving credit facility, cash generated by operations and proceeds from capital markets transactions and the sale of properties. We intend to finance our future capital expenditures utilizing similar financing sources. Our cash flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the amount of crude oil, natural gas and NGLs we are able to produce from existing wells;
- the prices at which crude oil, natural gas and NGLs are sold;
- the costs to produce crude oil, natural gas and NGLs; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower commodity prices, operating difficulties or for any other reason, our need for capital from other sources could increase, and there can be no assurance that such other sources of capital would be available at that time on reasonable terms or at all. If we raise funds by issuing additional equity securities, this would have a dilutive effect on existing shareholders. If we raise funds through the incurrence of debt, the risks we face with respect to our indebtedness would increase and we would incur additional interest expense. Our inability to obtain sufficient financing on acceptable terms would adversely affect our financial condition and profitability.

We have a substantial amount of debt and the cost of servicing, and risks related to refinancing, that debt could adversely affect our business. Those risks could increase if we incur more debt.

We have a substantial amount of indebtedness outstanding. As a result, a significant portion of our cash flows will be required to pay interest and principal on our indebtedness, and we may not generate sufficient cash flows from operations, or have future borrowing capacity available, to enable us to repay our indebtedness or to fund other liquidity needs.

Servicing our indebtedness and satisfying our other obligations will require a significant amount of cash. Our cash flow from operating activities and other sources may not be sufficient to fund our liquidity needs. Our ability to pay interest and principal on our indebtedness and to satisfy our other obligations will depend on our future operating performance, our financial condition and the availability of refinancing indebtedness, which will be affected by prevailing economic conditions and financial, business and other factors, many of which are beyond our control. We cannot assure you that our business will generate sufficient cash flow from operations, or that sufficient future borrowings will be available to us under our revolving credit facility or otherwise, to fund our liquidity needs.

A substantial decrease in our operating cash flow or an increase in our expenses could make it difficult for us to meet debt service requirements and could require us to modify our operations, including by curtailing our exploration and drilling programs, selling assets, reducing our capital expenditures, refinancing all or a portion of our existing debt or obtaining additional financing. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. In addition, the terms of our debt agreements could restrict us from implementing some of these alternatives.

In the absence of adequate cash from operations and other available capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. We may not be able to consummate these dispositions for fair market value, in a timely manner or at all. Furthermore, any proceeds that we could realize from any dispositions may not be adequate to meet our debt service obligations then due.

Covenants in our debt agreements currently impose, and future financing agreements may impose, significant operating and financial restrictions.

Our current debt agreements contain restrictions, and future financing agreements may contain additional restrictions, on our activities, including covenants that restrict our and our restricted subsidiaries’ ability to:

- incur additional debt;
- pay dividends on, redeem or repurchase stock;
- create liens;
- make specified types of investments;
- apply net proceeds from certain asset sales;
- engage in transactions with our affiliates;
- engage in sale and leaseback transactions;
- merge or consolidate;
- restrict dividends or other payments from restricted subsidiaries;
- sell equity interests of restricted subsidiaries; and
- sell, assign, transfer, lease, convey or dispose of assets.

Our revolving credit facility is secured by substantially all of our oil and gas properties as well as a pledge of all ownership interests in our operating subsidiaries. The restrictions contained in our debt agreements may prevent us from taking actions that we believe would be in the best interest of our business, and may make it difficult for us to successfully execute our business strategy or effectively compete with companies that are not similarly restricted. We may also incur future debt obligations that subject us to additional restrictive covenants.

Our revolving credit facility has substantial restrictions and financial covenants and our ability to comply with those restrictions and covenants is uncertain. Our lenders can unilaterally reduce our borrowing availability based on anticipated commodity prices.

We expect to depend on our revolving credit facility for part of our future capital needs. The terms of the credit agreement require us to comply with certain financial covenants. Our ability to comply with these covenants in the future is uncertain and will be affected by the levels of cash flows from operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under the revolving credit facility or other debt agreements could result in a default under those agreements, which could cause all of our existing indebtedness to become immediately due and payable.

The revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based upon projected revenues from the properties securing their loan. Decreases in the price of crude oil, natural gas or NGLs can be expected to have an adverse effect on the borrowing base. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Outstanding borrowings in excess of the borrowing base must be repaid immediately unless we pledge other crude oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility. Our inability to borrow additional funds under our revolving credit facility could adversely affect our operations and our financial results.

If we are unable to comply with the restrictions and covenants in our debt agreements, the resulting default could lead to an acceleration of payment of funds that we have borrowed and we may not have or be able to obtain the funds necessary to repay those amounts.

Any default under the agreements governing our indebtedness, including a default under our revolving credit facility that is not waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make us unable to pay principal and interest on our indebtedness and satisfy our other obligations. If we are unable to generate sufficient cash flows and are otherwise unable to obtain the funds necessary to meet required payments of principal and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such a default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, the lenders under our revolving credit facility could elect to terminate their commitments, cease making further loans and institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or liquidation. In addition, the default could result in a cross-default under other debt agreements. If our operating performance declines, we may in the future need to seek waivers from the required lenders under our revolving credit facility to avoid being in default and we may not be able to obtain such a waiver. If this occurs and no waiver is obtained, we would be in default under our revolving credit facility, the lenders could exercise their rights as described above, and we could be forced into bankruptcy or liquidation. We cannot assure you that we will be granted waivers or amendments to our debt agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our revolving credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase although the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness and for other purposes would decrease.

Notwithstanding our current indebtedness levels and restrictive covenants, we may still be able to incur substantial additional debt, which could exacerbate the risks described above.

We may be able to incur additional debt in the future. Although our debt agreements contain restrictions on our ability to incur indebtedness, those restrictions are subject to a number of exceptions. In particular, we may borrow under the revolving credit facility. We may also consider investments in joint ventures or acquisitions that may increase our indebtedness. Adding new debt to current debt levels could intensify the related risks that we and our subsidiaries now face.

Under the “successful efforts” accounting method that we use, unsuccessful exploratory wells must be expensed in the period in which they are determined to be non-productive, which reduces our net income in such periods.

We conduct exploratory drilling in order to identify additional opportunities for future development. Under the “successful efforts” method of accounting that we use, the cost of unsuccessful exploratory wells must be charged to expense in the period in which the wells are determined to be unsuccessful. In addition, lease costs for acreage condemned by the unsuccessful well must also be expensed. In contrast, unsuccessful development wells are capitalized as a part of the investment in the field where they are located. The costs of unsuccessful exploratory wells could result in a significant reduction in our profitability in periods in which the costs are required to be expensed.

Our commodity derivative activities could result in financial losses or reduced income from failure to perform by our counterparties, could limit our potential gains from increases in prices and could result in volatility in our net income.
We use commodity derivatives for a portion of the production from our own wells and for natural gas purchases and sales by our marketing subsidiary to achieve more predictable cash flows, to reduce exposure to adverse fluctuations in commodity prices, and to allow our natural gas marketing company to offer pricing options to natural gas sellers and purchasers. These arrangements expose us to the risk of financial loss in some circumstances, including when purchases or sales are different than expected or the counterparty to the commodity derivative contract defaults on its contractual obligations. In addition, many of our commodity derivative contracts are based on WTI or another crude oil or natural gas index price. The risk that the differential between the index price and the price we receive for the relevant production may change unexpectedly makes it more difficult to hedge effectively and increases the risk of a hedging-related loss. Also, commodity derivative arrangements may limit the benefit we would otherwise receive from increases in the prices for the relevant commodity.
At December 31, 2018, we had hedged a total of 19.6 MMBbls of crude oil and 26.4 Bcf of natural gas through 2020. These hedges may be inadequate to protect us from continuing and prolonged declines in crude oil and natural gas prices.
Since we do not designate our commodity derivatives as cash flow hedges, we do not currently qualify for use of hedge accounting; therefore, changes in the fair value of commodity derivatives are recorded in our income statements and our net income is subject to greater volatility than it would be if our commodity derivative instruments qualified for hedge accounting. For instance, if commodity prices rise significantly, this could result in significant non-cash charges during the relevant period, which could have a material negative effect on our net income.

Our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.
The occurrence of a significant accident or other event that is not fully covered by insurance, not properly or timely noticed to our carrier, or that is in excess of our insurance coverage, could have a material adverse effect on our operations and financial condition. Insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. In addition, pollution and environmental risks are generally not fully insurable.
The price of our common stock has been and may continue to be highly volatile, which may make it difficult for shareholders to sell our common stock when desired or at attractive prices.
The market price of our common stock is highly volatile and we expect it to continue to be volatile for the foreseeable future. Adverse events could trigger declines in the price of our common stock, including, among others:

- changes in production volumes, worldwide demand and prices for crude oil and natural gas;
- inability to hedge future production at the same pricing level as our current or prior hedges;
- changes in securities analysts’ estimates of our financial performance;
- fluctuations in stock market prices and volumes, particularly among securities of energy companies;
- changes in market valuations and valuation multiples of similar companies;
- changes in interest rates;
- announcements regarding adverse timing or lack of success in discovering, acquiring, developing and producing crude oil and natural gas resources;
- announcements by us or our competitors of significant contracts, new acquisitions, discoveries, commercial relationships, joint ventures or capital commitments;
- decreases in the amount of capital available to us, including as a result of borrowing base reductions and/or lenders ceasing to participate in our revolving credit facility syndicate;
- operating results that fall below market expectations or variations in our quarterly operating results;
- loss of a major customer;
- loss of a relationship with a partner;
- the occurrence and severity of environmental events and governmental and other third-party responses to the events; or

- additions or departures of key personnel.

External events, such as news concerning economic conditions, counterparties to our natural gas or crude oil derivatives arrangements, changes in government regulations impacting the crude oil and natural gas exploration and production industry or the movement of capital into or out of our industry, are also likely to affect the price of our common stock, regardless of our operating performance. For example, there have been recent efforts by some investment advisers, sovereign wealth funds, public pension funds, universities and other investment groups to divest themselves from investments in companies involved in fossil fuel extraction, and these efforts could reduce the trading prices of our securities. Similarly, our stock price could be adversely affected by changes in the way that analysts and investors assess the geological and economic characteristics of the basins in which we operate. Furthermore, general market conditions, including the level of, and fluctuations in, the trading prices of stocks generally could affect the price of our common stock. The stock markets regularly experience price and volume volatility that affects many companies' stock prices without regard to the operating performance of those companies. Volatility of this type may affect the trading price of our common stock. Similar factors could also affect the trading prices of our senior notes.

Our certificate of incorporation, bylaws and Delaware law contain provisions that may have an anti-takeover effect and may delay, defer or prevent a tender offer or takeover attempt, which may adversely affect the market price of our common stock.

Our certificate of incorporation and bylaws, and certain provisions of Delaware law, may have anti-takeover effects. For example, our certificate of incorporation authorizes our board of directors to issue preferred stock without shareholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us, including in circumstances where the acquisition is supported by the holders of a majority of our stock. In addition, other provisions of our certificate of incorporation, bylaws and Delaware law could make it more difficult for a third party to acquire control of us against the wishes of our board of directors, including:

- the organization of our board of directors as a classified board, which provides that approximately one-third of our directors are subject to election each year;
- bylaw provisions that require advance notice of some types of shareholder proposals; and
- Delaware law provisions which prohibit us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met.

In addition, shareholder activism in our industry has been increasing. If we are unable to work productively with activist or other shareholders, any resulting disagreements or disputes could require substantial management time and attention and could adversely affect our results of operations.

Derivatives legislation and regulation could adversely affect our ability to hedge crude oil and natural gas prices and increase our costs and adversely affect our profitability.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was enacted into law. The Dodd-Frank Act regulates derivative transactions, including our commodity hedging swaps, and could have a number of adverse effects on us, including the following:

- The Dodd-Frank Act may limit our ability to enter into hedging transactions, thus exposing us to additional risks related to commodity price volatility; commodity price decreases would then have an increased adverse effect on our profitability and revenues. Reduced hedging may also impair our ability to have certainty with respect to a portion of our cash flows, which could lead to decreases in capital spending and, therefore, decreases in future production and reserves.
- If, as a result of the Dodd-Frank Act or its implementing regulations, we are required to post cash collateral in connection with our derivative positions, this would likely make it impracticable to implement our current hedging strategy.
- Our derivatives counterparties are subject to significant requirements imposed as a result of the Dodd-Frank Act. We expect that these requirements will increase the cost to hedge because there will be fewer counterparties in the market and increased counterparty costs will be passed on to us.

The above factors could also affect the pricing of derivatives and make it more difficult for us to enter into hedging transactions on favorable terms.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings can found in the footnote titled Commitments and Contingencies - Litigation and Legal Items to our consolidated financial statements included elsewhere in this report.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our common stock, par value $0.01 per share, is traded on the NASDAQ Global Select Market under the symbol PDCE.

As of February 15, 2019, we had approximately 476 stockholders of record. Since inception, no cash dividends have been declared on our common stock. Cash dividends are restricted under the terms of our revolving credit facility, as well as the indentures governing our 6.125% senior notes due September 15, 2024 (the "2024 Senior Notes") and our 5.75% senior notes due May 15, 2026 (the "2026 Senior Notes"), and we presently intend to continue a policy of using retained earnings for the expansion of our business.

The following table presents information about our purchases of our common stock during the three months ended December 31, 2018:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
October 1 - 31, 2018	5,160	$ 47.20
November 1 - 30, 2018	—	—
December 1 - 31, 2018	7,022	29.00
Total fourth quarter 2018 purchases	12,182	36.71

(1) Purchases primarily represent shares purchased from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans.

STOCKHOLDER PERFORMANCE GRAPH

The performance graph below compares the cumulative total return of our common stock over the five-year period ended December 31, 2018 with the cumulative total returns for the same period for the Standard and Poor's ("S&P") 500 Index and the Standard Industrial Code ("SIC") Index. The SIC Index is a weighted composite of 233 crude petroleum and natural gas companies. The cumulative total stockholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our common stock on December 31, 2013, and in the S&P 500 Index and the SIC Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended/As of December 31,				
	2018	2017	2016 (1)	2015	2014 (2)
	(in millions, except per share data and as noted)				
Statement of Operations (From Continuing Operations):					
Crude oil, natural gas and NGLs sales	$1,390.0	$913.1	$497.4	$378.7	$471.4
Commodity price risk management gain (loss), net	145.2	(3.9)	(125.7)	203.2	310.3
Total revenues	1,548.7	921.6	382.9	595.3	856.2
Income (loss) from continuing operations	2.0	(127.5)	(245.9)	(68.3)	107.3
Earnings per share from continuing operations:					
Basic	$0.03	$(1.94)	$(5.01)	$(1.74)	$3.00
Diluted	0.03	(1.94)	(5.01)	(1.74)	2.93
Statement of Cash Flows:					
Net cash flows from:					
Operating activities	$889.3	$597.8	$486.3	$411.1	$236.7
Investing activities	(1,087.9)	(717.0)	(1,509.1)	(604.3)	(474.1)
Financing activities	18.1	65.0	1,266.1	178.0	60.3
Capital expenditures from development of crude oil and natural gas properties (3)	(946.4)	(737.2)	(436.9)	(599.5)	(623.8)
Acquisition of crude oil and natural gas properties	(180.0)	(15.6)	(1,073.7)	—	—
Balance Sheet:					
Total assets	$4,544.1	$4,420.4	$4,485.8	$2,370.5	$2,331.1
Working capital (deficit)	(166.6)	(16.4)	129.2	30.7	89.5
Total debt, net of unamortized discount and debt issuance costs	1,194.9	1,151.9	1,044.0	642.4	655.5
Total equity	2,526.7	2,507.6	2,622.8	1,287.2	1,137.4
Average Pricing and Production Expenses From Continuing Operations (per Boe and as a percent of sales for production taxes):					
Sales price (excluding net settlements on derivatives)	$34.61	$28.69	$22.43	$24.64	$50.72
Lease operating expenses	3.26	2.82	2.70	3.71	4.56
Transportation, gathering and processing	0.93	1.04	0.83	0.66	0.49
Production taxes	2.25	1.91	1.42	1.20	2.76
Production taxes (as a percent of sales)	6.5 %	6.6 %	6.3 %	4.9 %	5.4 %
Production (MBoe):					
Production from continuing operations	40,160	31,830	22,176	15,369	9,294
Production from discontinued operations	—	—	—	—	1,093
Total production	40,160	31,830	22,176	15,369	10,387
Total proved reserves (MMBoe)	544.9	452.9	341.4	272.8	250.1

(1)

In 2016, we closed an acquisition in the Delaware Basin for aggregate consideration of approximately $1.76 billion.

(2) In 2014, we completed the sale of our ownership interest in PDC Mountaineer, LLC ("PDCM"). Our proportionate share of PDCM's Marcellus Shale results of operations have been separately reported as discontinued operations.

(3) Includes impact of change in accounts payable related to capital expenditures.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes thereto included elsewhere in this report. Further, we encourage you to revisit the Special Note Regarding Forward-Looking Statements in Part I of this report.

SUMMARY

2018 Financial Overview of Operations and Liquidity

Production volumes increased 26 percent to 40.2 MMBoe in 2018 compared to 2017. The increase in production volumes was primarily attributable to the continued success of our horizontal Niobrara and Codell drilling program in the Wattenberg Field and growing production from our horizontal Wolfcamp drilling program in our Delaware Basin properties. Crude oil production increased 32 percent in 2018 and comprised approximately 42 percent of our total production. Natural gas production increased 23 percent and NGLs production increased 22 percent in 2018 compared to 2017. On a combined basis, total liquids production of crude oil and NGLs comprised 63 percent of production in 2018. For the month ended December 31, 2018, we maintained an average production rate of approximately 129,000 Boe per day, up from approximately 97,000 Boe per day for the month ended December 31, 2017.

Crude oil, natural gas and NGLs sales increased to $1.4 billion in 2018 compared to $913.1 million in 2017, due to a 26 percent increase in production, combined with a 21 percent increase in weighted average realized commodity prices. Crude oil, natural gas and NGLs sales increased 84 percent in 2017 as compared to 2016 due to a 44 percent increase in production, combined with a 28 percent increase in average realized commodity prices.

We had negative net settlements from our commodity derivative contracts of $115.5 million for 2018 as compared to positive net settlements of $13.3 million and $208.1 million for 2017 and 2016, respectively. See Results of Operations - Commodity Price Risk Management, Net for further details of our settlements of derivatives and changes in the fair value of unsettled derivatives.

The combined revenue from crude oil, natural gas and NGLs sales and net settlements received on our commodity derivative instruments increased 38 percent to $1.3 billion in 2018 from $926.4 million in 2017. Such combined revenue of $926.4 million in 2017 represented an increase of 31 percent from $705.5 million in 2016.

During 2018, we recorded unproved and proved property impairment charges of $458.4 million, primarily resulting from identified current and anticipated near-term leasehold expirations within our non-focus areas of the Delaware Basin and our determination that we would no longer pursue plans to develop these properties. For more information regarding these charges see Results of Operations - Impairments of Properties.

In 2018, we generated a net income of $2.0 million or $0.03 per diluted share. Our net income was most negatively impacted by the aforementioned impairment charges.

During the same period, our adjusted EBITDAX, a non-U.S. GAAP financial measure, was $868.3 million, up 27 percent relative to 2017. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of adjusted EBITDAX and a reconciliation of adjusted EBITDAX to net income and cash from operating activities. The increase in our 2018 adjusted EBITDAX as compared to 2017 was primarily the result of the increase in crude oil, natural gas and NGLs sales of $476.9 million. This increase was partially offset by a decrease in derivative commodity settlements of $128.9 million, an increase in operating costs of $125.3 million and the reversal of a provision for uncollectible notes receivable of $40.2 million in 2017. In 2017 and 2016, our net loss per diluted share was $1.94 and $5.01, respectively, and our adjusted EBITDAX was $682.1 million and $459.8 million, respectively.

Our net cash flows from operating activities in 2018, 2017 and 2016 were $889.3 million, $597.8 million and $486.3 million, respectively, and our adjusted cash flows from operations, a non-U.S. GAAP financial measure, were $808.4 million, $582.1 million and $466.8 million, respectively.

Liquidity

Available liquidity as of December 31, 2018 was $1.3 billion, which was comprised of $1.4 million of cash and cash equivalents and $1.3 billion available for borrowing under our revolving credit facility at our current commitment level. We increased the commitment level on our revolving credit facility to $1.3 billion in October 2018.

We maintain a significant capital investment program to execute our development plans, which requires capital expenditures to be made in periods prior to initial production from newly-developed wells. Further, we use our available liquidity for other working capital requirements, acquisitions, support for letters of credit and for general corporate purposes. From time to time, these activities may result in a working capital deficit; however, we do not believe that our working capital deficit as of December 31, 2018 is an indication of a lack of liquidity. We intend to continue to manage our liquidity position by a variety of means, including through the generation of cash flows from operations, investment in projects with attractive rates of return, protection of cash flows on a portion of our anticipated sales through the use of an active commodity derivative hedging program, utilization of our borrowing capacity under our revolving credit facility and, if warranted, capital markets transactions from time to time.

Acquisitions

We closed the Bayswater Asset Acquisition in January 2018, acquiring approximately 7,400 net acres, 24 operated horizontal wells that were either DUCs or in-process wells at the time of closing and approximately 220 gross drilling locations. See the footnote titled Business Combination to our consolidated financial statements included elsewhere in this report for further details.

Acreage Exchanges

During 2018, we completed two acreage exchanges that consolidated our position in the core area of the Wattenberg Field, resulting in us acquiring approximately 14,800 net acres in exchange for 15,500 net acres.

2018 Drilling Overview

During the year ended December 31, 2018, we continued to execute our strategic plan to grow production while preserving our financial strength and liquidity. During 2018, we ran three drilling rigs in each of the Wattenberg Field and Delaware Basin.

The following tables summarizes our drilling and completion activity for the year ended December 31, 2018:

	Wells Operated by PDC					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2017	87	80.1	13	12.2	100	92.3
Wells spud	161	150.9	31	29.7	192	180.6
Acquired in-process (1)	24	18.2	—	—	24	18.2
Wells turned-in-line	(139)	(126.8)	(26)	(24.5)	(165)	(151.3)
In-process as of December 31, 2018	133	122.4	18	17.4	151	139.8

	Wells Operated by Others					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2017	14	2.6	8	1.0	22	3.6
Wells spud	25	3.4	9	1.1	34	4.5
Acquired DUCs (operated at December 31, 2018) (1)	(3)	(1.5)	—	—	(3)	(1.5)
Wells turned-in-line	(31)	(2.5)	(11)	(1.2)	(42)	(3.7)
In-process as of December 31, 2018	5	2.0	6	0.9	11	2.9

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(1) Represents DUCs and completed wells that had not been turned-in-line that we acquired with the Bayswater Asset Acquisition in January 2018.

Our in-process wells represent wells that are in the process of being drilled and/or have been drilled and are waiting to be fractured and/or for gas pipeline connection. Our DUCs are generally completed and turned-in-line within a year of drilling.

2019 Operational and Financial Outlook

We anticipate that our production for 2019 will range between 46 MMBoe to 50 MMBoe, or approximately 126,000 Boe to 137,000 Boe per day for the year. We expect that approximately 41 to 45 percent of our 2019 production will be comprised of crude oil and approximately 21 to 23 percent will be NGLs, for total liquids of approximately 62 to 68 percent. Our planned 2019 capital investments in crude oil and natural gas properties, which we expect to be between $810 million and $870 million, are focused on continued execution of our development plans in the Wattenberg Field and Delaware Basin.

In 2019, we also expect to spend approximately $20 million for corporate capital, the majority of which is related to the implementation of an ERP system to replace our existing operating and financial systems. This long-planned investment is being made to enhance maintenance of our financial records, improve operational functionality and provide timely information to our management team related to the operation of the business.

We believe that we maintain a degree of operational flexibility to control the pace of our capital spending. As we execute our capital investment program, we continually monitor, among other things, expected rates of return, the political environment and our remaining inventory in order to best meet our short- and long-term corporate strategy. Should commodity pricing or the operating environment deteriorate, we may determine that an adjustment to our development plan is appropriate.

Wattenberg Field. We are drilling in the horizontal Niobrara and Codell plays in the rural areas of the core Wattenberg Field, which is further delineated between the Kersey, Prairie and Plains development areas. Our 2019 capital investment program for the Wattenberg Field is approximately 60 percent of our total capital investments in crude oil and natural gas properties, of which approximately 90 percent is expected to be invested in operated drilling and completion activity. We plan to drill standard-reach lateral (“SRL”), mid-reach lateral (“MRL”) and extended-reach lateral (“XRL”) wells in 2019, the majority of which will be in the Kersey area of the field. In 2019, we anticipate spudding approximately 135 to 150 operated wells and turning-in-line approximately 110 to 125 operated wells. We expect to drill at a three-rig pace in 2019 with an average development cost per well of between $3 million and $5 million, depending upon the lateral length of the well. The remainder of the Wattenberg Field capital investment program is expected to be used for non-operated drilling, land, capital workovers and facilities projects.

Delaware Basin. Our 2019 capital investment program for the Delaware Basin contemplates operating between a two- and three-rig pace throughout the year. Total capital investments in crude oil and natural gas properties in the Delaware Basin for 2019 are expected to be approximately 40 percent of our total capital investments in crude oil and natural gas properties, of which approximately 80 percent is allocated to spud approximately 25 to 30 operated wells and turn-in-line approximately 20 to 25 operated wells. We plan to drill MRL and XRL wells in 2019 with an expected average development cost per well of between $11.5 million and $13 million, depending upon the lateral length of the well. We do not plan to drill any SRL wells in the Delaware Basin in 2019. Based on the timing of our operations and requirements to hold acreage, we may elect to drill wells different from or in addition to those currently anticipated as we are continuing to analyze the terms of the relevant leases. We plan to use approximately 20 percent of our budgeted capital for midstream assets, leasing, non-operated capital, seismic and technical studies and facilities.

We are in the process of actively marketing our Delaware Basin crude oil gathering, natural gas gathering and produced water gathering and disposal assets for sale and currently expect to execute agreements for the sales of these assets in the first half of 2019. We anticipate making capital investments for midstream assets of approximately $40 million in 2019, a portion of which would be made prior to such sales depending on the timing of the divestitures. Such expenditures are included in the Delaware Basin capital investment amounts noted above. We expect that we would recover a portion of these expenditures upon settlement of the final sale prices.

Financial Guidance. We are committed to our disciplined approach to managing our development plans and expect that cash flows from operations in 2019 will exceed our capital investments in crude oil and natural gas properties assuming an average NYMEX crude oil price of at least $50.00. Based on our current production forecast for 2019 and our average 2019 price assumptions of $55.00 for NYMEX crude oil and $3.00 for NYMEX natural gas, we expect 2019 cash flows from operations to exceed our capital investments in crude oil and natural gas properties by approximately $65.0 million. Assuming a NYMEX crude oil price of $50.00, we expect cash flows from operations to exceed our capital investments in crude oil and natural gas properties by approximately $25.0 million. We anticipate that capital investments will exceed cash flows from operations during the first half of 2019 and expect cash flows from operations to exceed capital investment during the remainder of the year.

Assuming a NYMEX crude oil price of $45.00, we expect cash flows from operations to approximate our capital investments in crude oil and natural gas properties. A significant decline in NYMEX crude oil prices below approximately $45.00 per barrel would negatively impact our results of operations, financial condition and future development plans. Our leverage ratio, as defined in our revolving credit facility agreement, is expected to decrease from 1.4 as of the end of 2018 to approximately 1.3 by the end of 2019 based on anticipated production and $50.00 to $55.00 NYMEX crude oil prices. We may revise our 2019 capital investment program during the year as a result of, among other things, changes in commodity prices or our internal long-term outlook for commodity prices, requirements to hold acreage, the cost of services for drilling and well completion activities, drilling results, changes in our borrowing capacity, a significant change in cash flows, regulatory issues, requirements to maintain continuous activity on leaseholds or acquisition and/or divestiture opportunities.

We currently expect similar levels of financial performance and growth in 2020 as we anticipate experiencing in 2019. Based upon similar pricing assumptions used in our 2019 outlook and our focus on capital investment discipline, we currently anticipate increasing free cash flow in 2020.

The following table provides projected financial guidance for 2019:

	Low	High
Operating Expenses		
Lease operating expenses ($/Boe)	$2.85	$3.15
Transportation, gathering and processing expenses ("TGP") ($/Boe)	$0.80	$1.00
Production taxes (% of crude oil, natural gas and NGL sales)	6 %	7 %
General and administrative expense ($/Boe)	$3.00	$3.40
Estimated Price Realizations (% of NYMEX, excludes TGP)		
Crude oil	90 %	95 %
Natural gas	50 %	55 %
NGLs	30 %	35 %

Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results:

	Year Ended December 31,			Percent Change	
	2018	2017	2016	2018-2017	2017-2016
	(dollars in millions, except per unit data)				
Production:					
Crude oil (MBbls)	16,963	12,902	8,728	31.5 %	47.8 %
Natural gas (MMcf)	88,017	71,689	51,730	22.8 %	38.6 %
NGLs (MBbls)	8,527	6,981	4,826	22.1 %	44.7 %
Crude oil equivalent (MBoe)	40,160	31,830	22,176	26.2 %	43.5 %
Average Boe per day (Boe)	110,027	87,206	60,590	26.2 %	43.9 %
Crude Oil, Natural Gas and NGLs Sales:					
Crude oil	$1,038.0	$625.0	$348.9	66.1 %	79.1 %
Natural gas	163.2	158.3	91.6	3.1 %	72.8 %
NGLs	188.8	129.8	56.9	45.5 %	128.1 %
Total crude oil, natural gas and NGLs sales	$1,390.0	$913.1	$497.4	52.2 %	83.6 %
Net Settlements on Commodity Derivatives:					
Crude oil	$(124.4)	$(2.7)	$165.2	*	(101.6)%
Natural gas	13.9	23.3	42.9	(40.3)%	(45.7)%
NGLs (propane portion)	(5.0)	(7.3)	—	(31.5)%	*
Total net settlements on derivatives	$(115.5)	$13.3	$208.1	*	(93.6)%
Average Sales Price (excluding net settlements on derivatives):					
Crude oil (per Bbl)	$61.19	$48.45	$39.96	26.3 %	21.2 %
Natural gas (per Mcf)	1.85	2.21	1.77	(16.3)%	24.9 %
NGLs (per Bbl)	22.14	18.59	11.80	19.1 %	57.5 %
Crude oil equivalent (per Boe)	34.61	28.69	22.43	20.6 %	27.9 %
Average Costs and Expenses (per Boe):					
Lease operating expenses	$3.26	$2.82	$2.70	15.6 %	4.4 %
Production taxes	2.25	1.91	1.42	17.8 %	34.5 %
Transportation, gathering and processing expenses	0.93	1.04	0.83	(10.6)%	25.3 %
General and administrative expense	4.25	3.78	5.07	12.4 %	(25.4)%
Depreciation, depletion and amortization	13.94	14.74	18.80	(5.4)%	(21.6)%
Lease Operating Expenses by Operating Region (per Boe):					
Wattenberg Field	$2.99	$2.48	$2.70	20.6 %	(8.1)%
Delaware Basin	4.14	5.16	8.79	(19.8)%	(41.3)%
Utica Shale (1)	3.46	1.66	1.75	108.4 %	(5.1)%

*Percentage change is not meaningful or equal to or greater than 300% or not applicable.
Amounts may not recalculate due to rounding.

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(1) In March 2018, we completed the disposition of our Utica Shale properties.

Crude Oil, Natural Gas and NGLs Sales

The year-over-year change in crude oil, natural gas and NGLs sales revenue were primarily due to the following:

	Year Ended December 31,	
	2018	2017
	(in millions)	
Increase in production	$261.6	$227.5
Increase in average crude oil price	216.1	109.6
Increase (decrease) in average natural gas price	(31.1)	31.2
Increase in average NGLs price	30.3	47.4
Total increase in crude oil, natural gas and NGLs sales revenue	$476.9	$415.7

Crude Oil, Natural Gas and NGLs Production

The following table presents crude oil, natural gas and NGLs production.

	Year Ended December 31,				
				Change	
Production by Operating Region	2018	2017	2016	2018-2017	2017-2016
Crude oil (MBbls)					
Wattenberg Field	12,809	10,922	8,230	17.3 %	32.7 %
Delaware Basin	4,108	1,699	79	141.8 %	*
Utica Shale (1)	46	281	419	(83.6)%	(32.9)%
Total	16,963	12,902	8,728	31.5 %	47.8 %
Natural gas (MMcf)					
Wattenberg Field	68,326	60,106	48,889	13.7 %	22.9 %
Delaware Basin	19,277	9,410	373	104.9 %	*
Utica Shale (1)	414	2,173	2,468	(80.9)%	(12.0)%
Total	88,017	71,689	51,730	22.8 %	38.6 %
NGLs (MBbls)					
Wattenberg Field	6,455	5,876	4,568	9.9 %	28.6 %
Delaware Basin	2,038	917	36	122.2 %	*
Utica Shale (1)	34	188	222	(81.9)%	(15.3)%
Total	8,527	6,981	4,826	22.1 %	44.7 %
Crude oil equivalent (MBoe)					
Wattenberg Field	30,652	26,815	20,945	14.3 %	28.0 %
Delaware Basin	9,359	4,184	178	123.7 %	*
Utica Shale (1)	149	831	1,053	(82.1)%	(21.1)%
Total	40,160	31,830	22,176	26.2 %	43.5 %
Average crude oil equivalent per day (Boe)					
Wattenberg Field	83,978	73,466	57,227	14.3 %	28.4 %
Delaware Basin	25,641	11,463	486	123.7 %	*
Utica Shale (1)	408	2,277	2,877	(82.1)%	(20.9)%
Total	110,027	87,206	60,590	26.2 %	43.9 %

* Percentage change is not meaningful or equal to or greater than 300 percent. Amounts may not recalculate due to rounding.

(1) In March 2018, we completed the disposition of our Utica Shale properties.

The following table presents our crude oil, natural gas and NGLs production ratio by operating region:

	Year Ended December 31,		
Production Ratio by Operating Region	2018	2017	2016
Wattenberg Field			
Crude oil	42 %	41 %	39 %
Natural gas	37 %	37 %	39 %
NGLs	21 %	22 %	22 %
Total	100%	100%	100%
Delaware Basin			
Crude oil	44 %	41 %	45 %
Natural gas	34 %	37 %	35 %
NGLs	22 %	22 %	20 %
Total	100%	100%	100%
Utica Shale (1)			
Crude oil	31 %	34 %	40 %
Natural gas	46 %	43 %	39 %
NGLs	23 %	23 %	21 %
Total	100%	100%	100%

(1) In March 2018, we completed the disposition of our Utica Shale properties.

Midstream Capacity

Our ability to market our production depends substantially on the availability, proximity and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. If adequate midstream facilities and services are not available to us on a timely basis and at acceptable costs, our production and results of operations could be adversely affected. Both of our current areas of operation have seen substantial development in recent years, and this has made it more difficult for providers of midstream infrastructure and services to keep pace with the corresponding increases in field-wide production. The ultimate timing and availability of adequate infrastructure is not within our control and we could experience capacity constraints for extended periods of time that would negatively impact our ability to meet our production targets. Weather, regulatory developments and other factors also affect the adequacy of midstream infrastructure.

Wattenberg Field. Elevated line pressures on gas gathering facilities have adversely affected production from the Wattenberg Field from time to time, most recently beginning in mid-2017 and continuing into the fourth quarter of 2018. DCP completed its Mewbourn 3 Plant in August of 2018. This project, along with associated new compression, resulted in significant incremental capacity being added to the DCP system. System pressures began to decrease as these projects were started and reached full capacity during the third and fourth quarters of 2018. Concurrently, additional residue pipeline capacity became available as pipeline expansion projects were completed and commissioned in November 2018. As a result, system pressures have recently been maintained at a lower level than during the latter part of 2017. These lower pressures, along with the system improvements implemented by DCP to prevent freezes, combined with relatively mild weather in late 2018, resulted in a significant reduction in line freezes compared to those experienced during late 2017.

DCP continues to make progress on construction of its O’Conner 2 Plant, which we expect to be completed by the end of the second quarter of 2019. We expect that the start-up of the O’Conner 2 Plant will further reduce the line pressures on the system, while providing additional processing capacity for incremental production associated with our ongoing drilling program. This is the second plant that includes baseline volume commitments for us and the other operators and guarantees a specified profit margin to DCP for a three-year period, beginning on the initial start-up date of the plant. Under our current drilling plans and in the current commodity pricing environment, we currently expect to satisfy the volume commitment and profit margin requirements with minimal payment from us. See the footnote titled Commitments and Contingencies to our consolidated financial statements included elsewhere in this report for additional details regarding these agreements.

We have been engaged with DCP in planning for further incremental increases to the processing capacity in the field and it is currently our expectation that an additional plant will be constructed and commissioned on DCP's system in mid-2020. We also continue to work with our other midstream service providers in the field in an effort to ensure all of the existing infrastructure is fully utilized and that all options for system expansion are evaluated and implemented to the extent possible.

Additional residue and NGL takeaway pipeline expansions/conversions are expected to be completed in the third and fourth quarters of 2019 to help ensure that all products associated with additional processing capacity will be transported to market.

NGL fractionation on the Gulf Coast and Conway is running at full capacity and this could potentially impact the operation of gas plants in the Wattenberg Field. While our Wattenberg Field operations are not currently being impacted by NGL fractionation capacity constraints, the limitation on NGL fractionation capacity did limit the throughput of some gas processing plants in the field for a portion of the fourth quarter of 2018. Limitations on downstream fractionation capacity could limit the ability of our service providers to adjust ethane and propane recoveries to optimize the plant product mix to maximize revenue. Additional fractionation capacity is scheduled to come online later in 2019 and in 2020.

Delaware Basin. Like other producers, we from time to time enter into volume commitments with midstream providers in order to induce them to provide increased capacity. If our production falls below the level required under these agreements, we could be subject to substantial penalties. In the second quarter of 2018, we entered into firm sales and pipeline agreements for portions of our Delaware Basin crude oil and natural gas production, respectively. The crude oil agreement runs through December 2023 and provides for firm physical takeaway for all of our forecasted 2019 Delaware Basin crude oil volumes. This agreement provides us with price diversification through realization of export market pricing that includes access to a Corpus Christi terminal and exposure to Brent-weighted prices. As a result of this agreement, we expect to realize approximately 94 percent of West Texas Intermediate ("WTI") crude oil pricing for our total Delaware Basin production in 2019, after deducting transportation and other related marketing expenses. Our actual realization for Delaware Basin production for 2018 was 95 percent of WTI crude oil pricing. We are currently not producing sufficient volumes to satisfy this volume commitment in the Delaware Basin; although at current commodity prices we have been able to profitably satisfy our obligations under the agreement with volumes purchased from third parties, this may not continue to be the case.

Our Delaware Basin natural gas sales agreements run through December 2021 and provide for firm physical takeaway of amounts that vary between 50,000 MMbtu and 115,000 MMbtu per day of our natural gas volumes from the basin during the term of the agreements. We installed additional compression in the Central area of the basin during the third quarter of 2018, which allowed us to move our Central area natural gas volumes with minimal flaring.

Our production from the Delaware Basin was not materially affected by midstream or downstream capacity constraints during 2018. However, natural gas takeaway capacity downstream of in-field gathering and processing facilities in the basin is operating close to capacity, and near-term production constraints are possible.
As discussed above, NGL fractionation on the Gulf Coast and Conway is running at full capacity, and this could potentially impact the operation of gas plants in the Delaware Basin. In addition, residue pipeline and downstream crude oil pipelines in the Delaware Basin are operating at high utilization rates. We expect additional residue gas and crude oil pipelines to be available in early 2020, and additional NGL fractionation infrastructure to be available starting in mid-2019, with more projects scheduled to be completed in 2020.
See Item 1A. Risk Factors - The marketability of our production is dependent upon transportation and processing facilities, the capacity and operation of which we do not control. Market conditions or operational impediments affecting midstream facilities and services could hinder our access to crude oil, natural gas and NGL markets, increase our costs or delay production. Our efforts to address midstream issues may not be successful.

Crude Oil, Natural Gas and NGLs Pricing

Our results of operations depend upon many factors. Key factors include the price of crude oil, natural gas and NGLs and our ability to market our production effectively. Crude oil, natural gas and NGL prices have a high degree of volatility and our realizations can change substantially. Our realized sales prices for crude oil and NGLs increased and our realized prices for natural gas decreased during 2018 as compared to 2017. NYMEX average daily crude oil prices increased 27 percent and NYMEX first-of-the-month natural gas prices decreased slightly as compared to 2017. Our realized sales prices for crude oil, natural gas and NGLs increased during 2017 compared to 2016. NYMEX crude oil prices increased 18 percent and NYMEX natural gas prices increased 26 percent as compared to 2016.

The following tables present weighted-average sales prices of crude oil, natural gas and NGLs for the periods presented.

	Year Ended December 31,				
Weighted-Average Sales Price by Operating Region				Change	
(excluding net settlements on derivatives)	2018	2017	2016	2018-2017	2017-2016
Crude oil (per Bbl)					
Wattenberg Field	$61.14	$48.48	$39.99	26.1 %	21.2 %
Delaware Basin	61.37	48.68	49.28	26.1 %	(1.2)%
Utica Shale (1)	58.10	45.63	37.62	27.3 %	21.3 %
Weighted-average price	61.19	48.45	39.96	26.3 %	21.2 %
Natural gas (per Mcf)					
Wattenberg Field	1.90	2.19	1.77	(13.2)%	23.7 %
Delaware Basin	1.66	2.26	2.78	(26.5)%	(18.7)%
Utica Shale (1)	2.68	2.40	1.58	11.7 %	51.9 %
Weighted-average price	1.85	2.21	1.77	(16.3)%	24.9 %
NGLs (per Bbl)					
Wattenberg Field	20.58	17.75	11.59	15.9 %	53.1 %
Delaware Basin	27.06	22.64	17.87	19.5 %	26.7 %
Utica Shale (1)	24.29	25.06	15.11	(3.1)%	65.9 %
Weighted-average price	22.14	18.59	11.80	19.1 %	57.5 %
Crude oil equivalent (per Boe)					
Wattenberg Field	34.13	28.55	22.38	19.5 %	27.6 %
Delaware Basin	36.25	29.80	31.50	21.6 %	(5.4)%
Utica Shale (1)	30.98	27.36	21.88	13.2 %	25.0 %
Weighted-average price	34.61	28.69	22.43	20.6 %	27.9 %

* Percentage change is not meaningful or equal to or greater than 300 percent.
Amounts may not recalculate due to rounding.

(1) In March 2018, we completed the disposition of our Utica Shale properties.

Crude oil, natural gas and NGLs revenues are recognized when we have transferred control of crude oil, natural gas or NGLs production to the purchaser. We consider the transfer of control to have occurred when the purchaser has the ability to direct the use of, and obtain substantially all of the remaining benefits from, the crude oil, natural gas or NGLs production. We record sales revenue based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes based on company-measured volume readings. We then adjust our crude oil, natural gas and NGLs sales in subsequent periods based on the data received from our purchasers that reflects actual volumes delivered and actual prices received.

Our crude oil, natural gas and NGLs sales are recorded using either the “net-back” or "gross" method of accounting, depending upon the related purchase agreement. We use the net-back method when control of the crude oil, natural gas or NGLs has been transferred to the purchasers of these commodities that are providing transportation, gathering or processing services. In these situations, the purchaser pays us proceeds based on a percent of the proceeds or have fixed our sales price at index less specified deductions. The net-back method results in the recognition of a net sales price that is lower than the indices for which the production is based because the operating costs and profit of the midstream facilities are embedded in the net price we are paid.

We use the gross method of accounting when control of the crude oil, natural gas or NGLs is not transferred to the purchasers and the purchaser does not provide transportation, gathering or processing services as a function of the price we receive. Rather, we contract separately with midstream providers for the applicable transport and processing on a per unit basis. Under this method, we recognize revenues based on the gross selling price and recognize transportation, gathering and processing expenses.

Under the New Revenue Standard, certain crude oil and natural gas sales that were recognized using the gross method prior to the adoption of the New Revenue Standard are recognized using the net-back method. If we had adopted the New Revenue Standard on January 1, 2017, we estimate that the average realization percentages before transportation, gathering and processing expenses for 2017 would not have differed materially from the average realization percentages shown for the periods shown below. Further, the net realized price after transportation, gathering and processing expenses would not have changed. See the footnote titled Revenue Recognition to our consolidated financial statements included elsewhere in this report for a more detailed discussion.

As discussed above, we enter into agreements for the sale and transportation, gathering and processing of our production, the terms of which can result in variances in the per unit realized prices that we receive for our crude oil, natural gas and NGLs. Information related to the components and classifications in the consolidated statements of operations is shown below. For crude oil, the average NYMEX prices shown below are based upon average daily prices throughout each month and, for natural gas, the average NYMEX pricing is based upon first-of-the-month index prices, as in each case this is the method used to sell the majority of these commodities pursuant to terms of the respective sales agreements. For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes. The average realized price both before and after transportation, gathering and processing expenses shown in the table below represents our approximate composite per barrel price for NGLs.

2018	Average NYMEX Price	Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Realization Percentage Before Transportation, Gathering and Processing Expenses		Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses	Average Realization Percentage After Transportation, Gathering and Processing Expenses	
Crude oil (per Bbl)	$ 64.77	$ 61.19	94	%	$ 0.94	$ 60.25	93	%
Natural gas (per MMBtu)	3.09	1.85	60	%	0.22	1.63	53	%
NGLs (per Bbl)	64.77	22.14	34	%	0.21	21.93	34	%
Crude oil equivalent (per Boe)	47.87	34.61	72	%	0.93	33.68	70	%

2017	Average NYMEX Price	Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Realization Percentage Before Transportation, Gathering and Processing Expenses		Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses	Average Realization Percentage After Transportation, Gathering and Processing Expenses	
Crude oil (per Bbl)	$ 50.95	$ 48.45	95	%	$ 1.41	$ 47.04	92	%
Natural gas (per MMBtu)	3.11	2.21	71	%	0.17	2.04	66	%
NGLs (per Bbl)	50.95	18.59	36	%	0.30	18.29	36	%

Crude oil equivalent (per Boe)	38.83	28.69	74	%	1.04	27.65	71	%

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2016	Average NYMEX Price	Average Realized Price Before Transportation, Gathering and Processing Expenses	Average Realization Percentage Before Transportation, Gathering and Processing Expenses	Average Transportation, Gathering and Processing Expenses	Average Realized Price After Transportation, Gathering and Processing Expenses	Average Realization Percentage After Transportation, Gathering and Processing Expenses
Crude oil (per Bbl)	$ 43.32	$ 39.96	92 %	$ 1.51	$ 38.45	89 %
Natural gas (per MMBtu)	2.46	1.77	72 %	0.07	1.70	69 %
NGLs (per Bbl)	43.32	11.80	27 %	0.28	11.52	27 %
Crude oil equivalent (per Boe)	32.22	22.43	70 %	0.83	21.60	67 %

Our average realization percentages for crude oil and NGLs for 2018 are consistent with those for 2017. The realization percentage for our natural gas sales has decreased as compared to 2017, primarily due to the widening of the basis between NYMEX and the indices upon which we sell our natural gas production.

Commodity Price Risk Management, Net

We use commodity derivative instruments to manage fluctuations in crude oil, natural gas and NGLs prices, including collars, fixed-price swaps and basis swaps on a portion of our estimated crude oil, natural gas and propane production. For our commodity swaps, we ultimately realize the fixed price value related to the swaps. See the footnote titled Commodity Derivative Financial Instruments to our consolidated financial statements included elsewhere in this report for a detailed presentation of our derivative positions as of December 31, 2018.

Commodity price risk management, net, includes cash settlements upon maturity of our derivative instruments, as well as the change in the fair value of unsettled commodity derivatives related to our crude oil, natural gas and propane production. Commodity price risk management, net, does not include derivative transactions related to our gas marketing, which are included in other income and other expenses.

Net settlements of commodity derivative instruments are based on the difference between the crude oil, natural gas and propane index prices at the settlement date of our commodity derivative instruments compared to the respective strike prices contracted for the settlements months that were established at the time we entered into the commodity derivative transaction. The net change in fair value of unsettled commodity derivatives is comprised of the net value increase or decrease in the beginning-of-period fair value of commodity derivative instruments that settled during the period, and the net change in fair value of unsettled commodity derivatives during the period or from inception of any new contracts entered into during the applicable period. The net change in fair value of unsettled commodity derivatives during the period is primarily related to shifts in the crude oil, natural gas and NGLs forward curves and changes in certain differentials.

The following table presents net settlements and net change in fair value of unsettled commodity derivatives included in commodity price risk management, net:

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Commodity price risk management gain (loss), net:			
Net settlements of commodity derivative instruments:			
Crude oil fixed price swaps and collars	$(139.7)	$(2.7)	$165.2
Crude oil basis protection swaps	15.2	—	—
Natural gas fixed price swaps and collars	(7.0)	19.5	41.9
Natural gas basis protection swaps	21.0	3.8	1.0
NGLs (propane portion) fixed price swaps	(5.0)	(7.3)	—
Total net settlements of commodity derivative instruments	(115.5)	13.3	208.1
Change in fair value of unsettled commodity derivative instruments:			
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	64.9	44.8	(220.0)
Crude oil fixed price swaps, collars and rollfactors	197.0	(77.9)	(78.6)
Natural gas fixed price swaps and collars	1.4	14.7	(37.1)
Natural gas basis protection swaps	(2.6)	5.7	1.9
NGLs (propane portion) fixed price swaps	—	(4.6)	—
Net change in fair value of unsettled commodity derivative instruments	260.7	(17.3)	(333.8)
Total commodity price risk management gain (loss), net	$145.2	$(4.0)	$(125.7)

Lease Operating Expenses

Lease operating expenses increased 46 percent to $131.0 million in 2018 compared to $89.6 million in 2017. The increase was primarily due to increases of $8.3 million for workover projects related to increased costs to plug and abandon wells in the Wattenberg Field, $5.7 million related to additional compressor and equipment rentals to combat high line pressures, $5.4 million in environmental remediation expense, $4.9 million related to midstream expense in the Delaware Basin, $4.9 million for payroll and employee benefits related to increases in headcount, $2.6 million related to produced water disposal expense and $1.2 million related to expense for non-operated wells. Lease operating expense per Boe increased by 16 percent to $3.26 for 2018 from $2.82 for 2017.

Lease operating expenses were $89.6 million in 2017 compared to $60.0 million in 2016. The $29.6 million increase in lease operating expenses in 2017 as compared to 2016 was primarily due to increases of $9.4 million for payroll and employee benefits related to increases in headcount, $5.6 million for produced water disposal, $5.6 million for increased workover projects, $3.9 million related to additional compressor rentals and $2.2 million for equipment rentals. The increases were slightly offset by a $1.5 million decrease in environmental remediation costs. Lease operating expense per Boe increased by four percent to $2.82 for 2017 from $2.70 for 2016.

Production Taxes

Production taxes are comprised mainly of severance tax and ad valorem tax, are directly related to crude oil, natural gas and NGLs sales and are generally assessed as a percentage of net revenues. From time to time, there are adjustments to the statutory rates for these taxes based upon activity levels and relative commodity prices from year-to-year.

Production taxes increased 49 percent to $90.4 million in 2018 compared to $60.7 million in 2017, primarily due to the 52 percent increase in crude oil, natural gas and NGLs sales for 2018 compared to 2017, as well as an increase in the ad valorem tax rate in the Delaware Basin related to an increase in assessed property values.

Production taxes increased 93 percent to $60.7 million in 2017 compared to $31.4 million in 2016, primarily due to the 84 percent increase in crude oil, natural gas and NGLs sales for 2017 compared to 2016, as well as an increase in tax rates.

Transportation, Gathering and Processing Expenses

Transportation, gathering and processing expenses increased 13 percent to $37.4 million in 2018 compared to 2017 and increased 80 percent in 2017 to $33.2 million compared to 2016. Transportation, gathering and processing expenses are primarily impacted by the volumes delivered through pipelines and for natural gas gathering and transportation operations. The change in 2018 as compared to 2017 is further impacted by decreases resulting from the adoption of the New Revenue Standard and the disposition of the Utica Shale properties. As discussed in Crude Oil, Natural Gas and NGLs Pricing, whether transportation, gathering and processing costs are presented separately or are reflected as a reduction to net revenue is a function of the terms of the relevant marketing contract.

Exploration, Geologic and Geophysical Expense

The following table presents the major components of exploration, geologic and geophysical expense:

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Exploratory dry hole costs	$0.1	$41.3	$—
Geological and geophysical costs	3.4	3.9	3.5
Operating, personnel and other	2.7	2.1	1.2
Total exploration expense	$6.2	$47.3	$4.7

Exploratory dry hole costs. During 2017, two exploratory dry holes, associated lease costs and related infrastructure assets in the Delaware Basin were expensed at a cost of $41.3 million. The conclusion to expense these items was based on our determination that the acreage on which these wells was drilled was exploratory in nature and, following drilling, that the hydrocarbon production was insufficient for the wells to be deemed economically viable.

Geological and geophysical costs. Geological and geophysical costs in 2018, 2017 and 2016 were primarily related to the portion of the purchase of seismic data related to unproved acreage in the Delaware Basin.

Impairment of Properties and Equipment

The following table sets forth the major components of our impairments of properties and equipment expense:

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Impairment of proved and unproved properties	$458.4	$285.5	$5.6
Amortization of individually insignificant unproved properties	—	0.4	1.4
Land and buildings	—	—	3.0
Total impairment of properties and equipment	$458.4	$285.9	$10.0

Impairment of proved and unproved properties. Amounts represent the retirement or expiration of certain leases that are no longer part of our development plan or that we do not plan to extend and will allow to expire. Deterioration of commodity prices or other operating circumstances could result in additional impairment charges.

During 2018, we recorded impairment charges totaling $458.4 million as we identified current and anticipated leasehold expirations within the Western Culberson County area of the Delaware Basin and made the determination that we would no longer pursue plans to develop these properties. The impaired non-focus leaseholds typically have a higher gas to oil ratio and a greater degree of geologic complexity than our other Delaware Basin properties. In 2019, we expect that we will allow approximately 18,300 gross (17,900 net) acres of our leaseholds in the Delaware Basin to expire. Of these leaseholds, we expect that approximately 9,500 gross and net acres and 8,600 gross (8,000 net) acres will expire in the first and third quarters, respectively, of 2019. Taking all expected 2019 expirations into account, we anticipate ending 2019 with approximately 40,100 gross (33,500 net) acres in the Delaware Basin. In 2020, we expect that we will allow approximately 3,400 gross (1,800 net) acres of our leaseholds in the Delaware Basin to expire. We are currently exploring strategic alternatives with respect to the acres expected to expire in 2019 and 2020 and believe that we may be able to monetize a portion of this acreage.

During 2017, we recorded a charge related to two exploratory dry holes we had drilled in the western area of our Culberson County acreage in the Delaware Basin, as referenced previously. We then assessed the impact of the dry holes and various factors related thereto, including the operational and geologic data obtained, the current increased cost environment for drilling and completion services in the Delaware Basin, our future commodity price outlook and the terms of the related lease agreements. Based on the results of this assessment, we concluded that the underlying geologic risk and the challenged economics of future capital expenditures reduced the likelihood that we would perform future development in this area over the remaining lease term for this acreage. Accordingly, we recorded an impairment of $251.6 million covering approximately 13,400 acres during 2017. The amount of the impairment was based on the value assigned to individual lease acres in the final purchase price allocation of our Delaware Basin acquisition. This allocation included the consideration paid to the sellers, including the effect of the non-cash impact from the deferred tax liability created at the time of the acquisition. We recorded approximately $29 million of additional lease impairments in the Delaware Basin and an impairment charge of $2.1 million related to the Utica Shale Divestiture. Due to the aforementioned events and circumstances, we also evaluated our proved property for possible impairment and concluded that no further impairments were necessary at that time.

Impairment of Goodwill

During 2017, we recorded goodwill impairment charges of $75.1 million resulting from the purchase price allocation of the assets acquired in the Delaware Basin. The impairment was primarily due to a combination of increases in per well development and operational costs and our drilling of two exploratory dry holes in the Delaware Basin subsequent to the acquisition. In conjunction with our then-current lower future commodity price outlook, we determined that a triggering event had occurred in the quarter ended September 30, 2017.

General and Administrative Expense

General and administrative expense increased 42 percent to $170.5 million in 2018 compared to 2017. The increase was primarily attributable to a $16.1 million increase in payroll and employee benefits, a $14.0 million increase in legal related costs, a $9.2 million increase in government relations expenses and a $6.3 million increase related to professional services. These increases were partially offset by a $0.9 million decrease related to environmental matters.

General and administrative expense increased seven percent to $120.4 million in 2017 compared to 2016. The increase was primarily attributable to an $8.1 million increase in payroll and employee benefits, a $4.4 million increase related to professional services, a $4.2 million increase in legal related costs, a $1.4 million increase in software licenses and subscriptions and a $1.3 million increase for the rental of additional office space. The increases were partially offset by the $12.2 million of legal and professional fees related to the acquisition in the Delaware Basin that were incurred in 2016.

Depreciation, Depletion and Amortization

Crude oil and natural gas properties. During 2018, 2017 and 2016, we invested $982.7 million, $788.0 million and $396.4 million, net of changes in accounts payable related to capital expenditures, in the development of our crude oil and natural gas properties, respectively. DD&A expense related to crude oil and natural gas properties is directly related to proved reserves and production volumes. DD&A expense related to crude oil and natural gas properties was $551.3 million, $462.5 million and $413.1 million in 2018, 2017 and 2016, respectively. The year-over-year changes in DD&A expense related to crude oil and natural gas properties were primarily due to the following:

	Year Ended December 31,	
	2018 - 2017	2017 - 2016
	(in millions)	
Increase in production	$127.9	$144.7
Decrease in weighted-average depreciation, depletion and amortization rates	(39.1)	(95.3)
Total increase in DD&A expense related to crude oil and natural gas properties	$88.8	$49.4

The following table presents our DD&A expense rates for crude oil and natural gas properties:

	Year Ended December 31,		
Operating Region/Area	2018	2017	2016
	(per Boe)		
Wattenberg Field	$12.58	$14.67	$19.11
Delaware Basin (1)	17.70	14.89	8.34
Utica Shale (2)	—	8.09	10.66
Total weighted-average	13.73	14.53	18.63

(1) The 2016 Delaware Basin rate represents one month of DD&A expense. Accordingly, the comparisons of the 2018 and 2017 rates to the 2016 rate are not meaningful.

(2) The Utica Shale properties were classified as held-for-sale during the third quarter of 2017; therefore, we did not record DD&A expense on these properties in 2018. In March 2018, we completed the disposition of our Utica Shale properties.

Provision for Uncollectible Notes Receivable

In 2016, we recorded a provision for uncollectible notes receivable of $44.0 million to impair two third-party notes receivable whose collection was not reasonably assured. In April 2017, we signed a definitive agreement and simultaneously closed on the sale of one of the associated notes receivable to an unrelated third-party for $40.2 million. Accordingly, we reversed $40.2 million of the provision for uncollectible notes receivable during 2017.

Accretion of Asset Retirement Obligations

Accretion of asset retirement obligations for 2018 decreased 20 percent to $5.1 million compared to 2017, and decreased 11 percent in 2017 to $6.3 million compared to 2016. The decreases in 2018 and 2017 were due to the replacement of vertical wells that have been plugged and abandoned with horizontal wells, which have a longer expected life.

Interest Expense

Interest expense decreased by $8.0 million to $70.7 million in 2018 compared to $78.7 million in 2017. The decrease was primarily related to a $38.1 million decrease in interest expense relating to the net settlement of previously outstanding senior notes in December 2017 and a $4.2 million increase in capitalized interest. The decreases were partially offset by a $32.2 million increase in interest expense related to the issuance of our 2026 Senior Notes in November 2017 and a $1.7 million increase in interest related to our revolving credit facility.

Interest expense increased by approximately $16.7 million to $78.7 million in 2017 compared to $62.0 million in 2016. The increase is primarily attributable to an $18.0 million increase in interest for the issuance of our 2024 Senior Notes, a $7.4 million increase in interest expense for the issuance of $200 million principal amount of our 1.125% convertible notes due 2021 (the "2021 Convertible Notes") in September 2016, a $3.1 million increase in interest expense for the issuance of our 2026 Notes in November 2017 and a $3.0 million increase in the utilization fee of our revolving credit facility. The increases were partially offset by a $9.3 million charge for a bridge loan commitment related to the 2016 acquisition of properties in the Delaware Basin, a $3.5 million decrease in interest expense resulting from the net settlement of our 2016 Convertible Notes in May 2016 and a $1.8 million decrease in interest expense resulting from the net settlement of our 2022 Notes in December 2017.

Interest costs capitalized in 2018, 2017 and 2016 were $9.2 million, $5.0 million and $4.5 million, respectively.

Loss on Extinguishment of Debt

The $24.7 million loss on extinguishment of debt relates to the redemption of the 2022 Senior Notes during the fourth quarter of 2017. The loss consists of a $19.4 million make-whole premium and the write-off of unamortized debt issuance costs of $5.4 million.

Provision for Income Taxes

Current income tax (expense) benefit in 2018, 2017 and 2016 was $0.7 million, $8.2 million and $9.9 million, respectively. Current income taxes generally relate to the cash that is paid or recovered for income taxes associated with the applicable period. The remaining portion of the total income tax provision is comprised of deferred income taxes, which are a result of differences in the timing of deductions from our U.S. GAAP presentation of financial statements and the income tax regulations.

Our effective income tax rates for 2018, 2017 and 2016 were 72.8 percent, 62.4 percent and 37.4 percent, respectively, on income (loss) from operations.

The 2018 rate differs from the federal statutory tax rate primarily due to state taxes, federal tax credits, valuation allowance for state tax attributes and nondeductible expenses that consist primarily of officers' compensation cost and government lobbying expenses.

The 2017 rate differs from the federal statutory rate primarily due to the reduction in the federal corporate income tax rate resulting from the 2017 Tax Cuts & Jobs Act ("The 2017 Act"), which increased the tax benefit rate by 33.7 percent. Additionally, the nondeductible goodwill impairment charge in 2017 reduced the 2017 tax rate by 7.7 percent. The 2017 tax rate was also impacted by state taxes.

The 2016 rate differs from the federal statutory tax rate, primarily due to state taxes and excess tax benefit from stock compensation, offset by nondeductible expenses that consist primarily of officers' compensation and government lobbying expenses.

As of the date of this report, we are current with our income tax filings in all applicable state jurisdictions. We continue to voluntarily participate in the Internal Revenue Service’s ("IRS") Compliance Assurance Program (the "CAP Program") for the 2018 and 2019 tax years. We have received a partial acceptance notice from the IRS for our filed 2017 federal tax return and the IRS's post filing review is currently ongoing.

Net Income (Loss)/Adjusted Net Income (Loss)

The factors resulting in changes in net income in 2018 and net loss in 2017 and 2016 are discussed above. These same reasons similarly impacted adjusted net income (loss), a non-U.S. GAAP financial measure, with the exception of the net change in fair value of unsettled derivatives, adjusted for taxes, of $198.3 million, $13.1 million and $208.9 million in 2018, 2017 and 2016, respectively. Adjusted net loss, a non-U.S. GAAP financial measure, was $196.3 million, $114.4 million and $37.0 million in 2018, 2017 and 2016 respectively. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of this non-U.S. GAAP financial measure.

Financial Condition, Liquidity and Capital Resources

Our primary sources of liquidity are cash flows from operating activities, our revolving credit facility, proceeds from debt and equity capital market transactions and asset sales. In 2018, our net cash flows from operating activities were $889.3 million.

Our primary source of cash flows from operating activities is the sale of crude oil, natural gas and NGLs. Fluctuations in our operating cash flows are principally driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile and we manage a portion of this volatility through our use of derivative instruments. We enter into commodity derivative instruments with maturities of no greater than five years from the date of the instrument. Our revolving credit facility imposes limits on the amount of our production we can hedge, and we may choose not to hedge the maximum amounts permitted. Therefore, we may still have fluctuations in our cash flows from operating activities due to the remaining non-hedged portion of our future production. Due to a decreasing leverage ratio that we have recently experienced, the percentage of our expected future production that we currently have hedged is lower than we have historically maintained and we anticipate that this may remain the case in the near future.

Our working capital fluctuates for various reasons, including, but not limited to, changes in the fair value of our commodity derivative instruments and changes in our cash and cash equivalents due to our practice of utilizing excess cash to reduce the outstanding borrowings under our revolving credit facility. At December 31, 2018, we had a working capital deficit of $166.6 million compared to a working capital deficit of $16.4 million at December 31, 2017. The decrease in working capital as of December 31, 2018 is primarily the result of a decrease in cash and cash equivalents of $179.3 million related to the Bayswater Asset Acquisition, partially offset by an increase in accounts payable of $31.8 million related to increased development and exploration activity.

Our cash and cash equivalents were $1.4 million at December 31, 2018 and availability under our revolving credit facility was $1.3 billion, providing for total liquidity of $1.3 billion as of December 31, 2018. Assuming a NYMEX crude oil price of $50.00, we expect cash flows from operations to exceed our capital investments in crude oil and natural gas properties in 2019 by approximately $25.0 million. We anticipate that capital investments will exceed cash flows from operations during the first half of 2019 and expect cash flows from operations to exceed capital investment during the remainder of the year. Our leverage ratio, as defined in our revolving credit facility agreement, is currently expected to decrease to approximately 1.3 by the end of 2019 based on anticipated production and $50.00 to $55.00 NYMEX crude oil prices.

We are in the process of actively marketing our Delaware Basin crude oil gathering, natural gas gathering and produced water gathering and disposal assets for sale and currently expect to execute agreements for the sales of these assets in the first half of 2019. We anticipate making capital investments for midstream assets during 2019, a portion of which would be made prior to such anticipated sales depending on the timing of the divestitures. We expect that we would recover a portion of these expenditures upon settlement of the final sale prices.

Based on our expected cash flows from operations, our cash and cash equivalents and availability under our revolving credit facility, we believe that we will have sufficient capital available to fund our planned activities through the 12-month period following the filing of this report.

Our revolving credit facility is available for working capital requirements, capital investments, acquisitions, to support letters of credit and for general corporate purposes. The borrowing base is based on, among other things, the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests. The revolving credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests on a quarterly basis. The financial tests, as defined per the revolving credit facility, include requirements to: (a) maintain a minimum current ratio of 1.0:1.0 and (b) not exceed a maximum leverage ratio of 4.0:1.0. At December 31, 2018, we were in compliance with all covenants in the revolving credit facility with a current ratio of 3.3:1.0 and a leverage ratio of 1.4:1.0. We expect to remain in compliance throughout the 12-month period following the filing of this report.

The indentures governing our 2024 Senior Notes and 2026 Senior Notes contain customary restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt including under our revolving credit facility, (b) make certain investments or pay dividends or distributions on our capital stock or purchase, redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) restrict the payment of dividends or other payments by restricted subsidiaries to us, (e) create liens that secure debt, (f) enter into transactions with affiliates and (g) merge or consolidate with another company. See the footnote titled Long-Term Debt to the accompanying consolidated financial statements included elsewhere in this report for more information regarding our revolving credit facility.

Cash Flows

Operating Activities. Our net cash flows from operating activities are primarily impacted by commodity prices, production volumes, net settlements from our commodity derivative positions, operating costs and general and administrative expenses. Cash flows provided by operating activities increased by $291.5 million to $889.3 million in 2018 as compared to 2017, primarily due to the increase in crude oil, natural gas and NGLs sales of $476.9 million and an increase in changes in assets and liabilities of $65.1 million. The increases were partially offset by a decrease in derivative commodity settlements of $128.9 million and increases in general and administrative expense of $50.1 million, lease operating expenses of $41.3 million and production taxes of $29.6 million.

Cash flows provided by operating activities increased by $111.6 million to $597.8 million in 2017 as compared to 2016, primarily due to the increase in crude oil, natural gas, and NGLs sales of $415.7 million. The increase was partially offset
by a decrease in derivative commodity settlements of $194.8 million and increases in lease operating expenses of $29.7 million,
production taxes of $29.3 million, interest expense of $16.7 million, transportation, gathering, and processing expenses of
$14.8 million, and increases in general and administrative expense of $7.9 million as well as a decrease in changes in assets
and liabilities of $13.0 million.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $226.3 million in 2018 to $808.4 million, and increased by $115.3 million in 2017 to $582.1 million, when compared to the respective prior years. These changes were primarily due to the same factors mentioned above for changes in cash flows provided by operating activities, without regard to changes in assets and liabilities.

Adjusted EBITDAX, a non-U.S. GAAP financial measure, increased by $186.2 million in 2018 to $868.3 million from $682.1 million in 2017, primarily as the result of the increase in crude oil, natural gas and NGLs sales of $476.9 million. This increase was partially offset by a decrease in derivative commodity settlements of $128.9 million, an increase in general and administrative expense of $50.1 million, an increase in lease operating expenses of $41.3 million, the sale of the note described below in 2017 to a third-party for $40.2 million, and an increase in production taxes of $29.6 million.

Adjusted EBITDAX, a non-U.S. GAAP financial measure, increased by $222.3 million in 2017 to $682.1 million from $459.8 million in 2016, primarily as the result of the increase in crude oil, natural gas, and NGLs sales of $415.7 million,
as well as the recording of a provision for a note receivable in 2016 of $44.0 million and the subsequent sale of the note in

2017 to a third-party for $40.2 million. The increase was partially offset by a decrease in derivative commodity settlements of
$194.8 million, and increases in lease operating expenses of $29.7 million, production taxes of $29.3 million, interest expense
of $16.7 million, transportation, gathering, and processing expenses of $14.8 million, and general and administrative expense
of $7.9 million.

See Item 7. Reconciliation of Non-U.S. GAAP Financial Measures for a reconciliation of our U.S. GAAP to non-U.S. GAAP financial measures.

Investing Activities. Because crude oil and natural gas production from a well declines rapidly in the first few years of production, we continue to invest significant amounts of capital in order to maintain and grow our production and replace our reserves. If capital markets are not available in the future, we will be limited to our cash flows from operations and liquidity under our revolving credit facility as the sources for funding our capital investments.

Cash flows from investing activities primarily consist of the acquisition, exploration and development of crude oil and natural gas properties, net of dispositions of crude oil and natural gas properties. Net cash used in investing activities of $1.1 billion during 2018 was primarily related to the purchase price of the Bayswater Asset Acquisition of $179.0 million and our drilling operations, including completion activities, of $946.4 million. Partially offsetting these investments was the receipt of approximately $39.0 million related to the divestiture of our Utica Shale properties.

Net cash used in investing activities during 2017 of $717.0 million was primarily related to cash utilized for our drilling operations, including completion activities of $737.2 million, a $21.0 million deposit toward the Bayswater Asset Acquisition, purchases of short-term investments of $49.9 million and a $9.3 million deposit with a third-party transportation service provider for surety of an existing firm transportation obligation. Partially offsetting these investments was the receipt of approximately $49.9 million related to the sale of short-term investments, $40.2 million from the sale of a promissory note and $5.4 million related to post-closing settlements of properties acquired in 2016.

Net cash used in investing activities during 2016 of $1.5 billion was primarily related to cash utilized for our acquisition in the Delaware Basin of $1.1 billion and $436.9 million for our drilling operations.

Financing Activities. Net cash from financing activities in 2018 of $18.1 million was comprised of net borrowings from our credit facility of $32.5 million, partially offset by $7.7 million of debt issuance costs and $5.1 million related to purchases of our stock.

Net cash from financing activities in 2017 of $65.0 million was primarily related to $592.4 million of net proceeds from issuance of the 2026 Senior Notes, partially offset by the $519.4 million used to redeem our 2022 Senior Notes.

Net cash from financing activities in 2016 of $1.3 billion was primarily related to the $855.1 million of net proceeds received from the issuance of 9.4 million shares of our common stock, $392.2 million of net proceeds from issuance of the 2024 Senior Notes and $193.9 million of net proceeds from issuance of the 2021 Convertible Notes, partially offset by the $115.0 million payment upon the maturity of the 2016 Convertible Notes and net payments of approximately $37.0 million to pay down amounts borrowed under our revolving credit facility.

Contractual Obligations and Contingent Commitments

The following table presents our contractual obligations and contingent commitments as of December 31, 2018:

	Payments due by period				
Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(in millions)				
Long-term liabilities reflected on the consolidated balance sheet (1)					
Long-term debt (2)	$1,233	$—	$200	$33	$1,000
Commodity derivative contracts (3)	5	3	2	—	—
Production tax liability	122	61	61	—	—
Deferred oil gathering credit	24	2	5	5	12
Asset retirement obligations	111	26	39	39	7
Other liabilities (4)	10	3	5	1	1
	1,505	95	312	78	1,020
Commitments, contingencies and other arrangements (5)					
Interest on long-term debt (6)	457	67	135	127	128
Operating leases	28	6	13	7	2
Firm transportation and processing agreements (7)	430	107	152	124	47
	915	180	300	258	177
Total	$2,420	$275	$612	$336	$1,197

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(1) Table does not include deferred income tax liability to taxing authorities of $198.1 million due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(2) Amount presented does not agree with the consolidated balance sheets in that it excludes $22.8 million of unamortized debt discount and $14.9 million of unamortized debt issuance costs.

(3) Represents our gross liability related to the fair value of derivative positions.

(4) Includes deferred compensation to former executive officers, deferred payments related to firm transportation agreements and capital leases.

(5) The table does not include termination benefits related to employment agreements with our executive officers, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(6) Amounts presented include $276.0 million to the holders of our 2026 Senior Notes, $147.0 million to the holders of our 2024 Senior Notes and $6.8 million payable to the holders of our 2021 Convertible Notes. Amounts also include interest of $21.0 million related to unutilized commitments at a rate of 0.375 percent per annum.

(7) Represents our gross commitment which includes volumes produced by us, purchased from third parties and produced by our affiliated partnerships and other third-party working, royalty and overriding royalty interest owners whose volumes we market on their behalf. This includes anticipated and estimated commitments associated with two new gas processing facilities by our primary mid-stream provider. The timing of such payments has been estimated and is subject to change based on the completion of construction and the commencement of operations by the midstream provider.

From time to time, we are a party to various legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse effect on our business, financial condition, results of operations or liquidity. Information regarding our legal proceedings can be found in the footnote titled Commitments and Contingencies - Litigation and Legal Items to our consolidated financial statements included elsewhere in this report.

Critical Accounting Policies and Estimates

We have identified the following policies as critical to business operations and the understanding of our results of operations. This is not a comprehensive list of all of the accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by U.S. GAAP, with no need for our judgment in the application. There are also areas in which our judgment in selecting available alternatives would not produce a materially different result. However, certain of our accounting policies are particularly important to the presentation of our financial position and results of operations and we may use significant judgment in their application. As a result, they are subject to an inherent degree of uncertainty. In applying those policies, we use our judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on historical experience, observation of trends in the industry and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see the footnote titled Summary of Significant Accounting Policies to our consolidated financial statements included elsewhere in this report.

Crude Oil and Natural Gas Properties. We account for our crude oil and natural gas properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depreciated or depleted by the unit-of-production method based on estimated proved developed producing reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved reserves.

Annually, we engage independent petroleum engineers to prepare reserve and economic evaluations of all our properties on a well-by-well basis as of December 31. We adjust our crude oil and natural gas reserves for major acquisitions, new drilling and divestitures during the year as needed. The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also 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, revisions in existing reserve estimates occur. Although every reasonable effort is made to ensure that reserve estimates reported represent our most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates over time. Because estimates of reserves significantly affect our DD&A expense, a change in our estimated reserves could have an effect on our net income (loss).

Exploration costs, including geological and geophysical expenses, the acquisition of seismic data covering unproved acreage and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized, but are charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify completion as a producing well and we are making sufficient progress assessing our reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful prior to the issuance of the financial statements, the costs incurred prior to the end of the reporting period are charged to exploration expense. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the well is classified as a "suspended well" until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when we are able to make a final determination of a well’s productive status, the well is removed from suspended well status and the proper accounting treatment is applied.

Acquisition costs of unproved properties are capitalized when incurred until such properties are transferred to proved properties or charged to expense. Unproved crude oil and natural gas properties with individually significant acquisition costs are periodically assessed, and any impairment in value is charged to impairment of crude oil and natural gas properties. The amount of impairment recognized on unproved properties which are not individually significant is determined by amortizing the costs of such properties within appropriate fields based on our historical experience, acquisition dates and average lease terms, with the amortization recognized in impairment of properties and equipment. The valuation of unproved properties is subjective and requires us to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual realizable values.

We assess our crude oil and natural gas properties for possible impairment annually, or upon a triggering event, by comparing carrying value to estimated undiscounted future net cash flows on a field-by-field basis using estimated production and prices at which we reasonably estimate the commodities will be sold. Any impairment in value is charged to impairment of properties and equipment. The estimates of future prices may differ from current market prices of crude oil and natural gas. Any downward revisions in estimates to our reserve quantities, expectations of falling commodity prices or rising operating costs could result in a triggering event, and therefore, a reduction in undiscounted future net cash flows and an impairment of our crude oil and natural gas properties. Although our cash flow estimates are based on the relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

Crude Oil, Natural Gas and NGLs Sales Revenue Recognition. Crude oil, natural gas and NGLs revenues are recognized when we have transferred control of crude oil, natural gas, or NGLs production to the purchaser. We consider the transfer of control to have occurred when the purchaser has the ability to direct the use of, and obtain substantially all of the remaining benefits from, the crude oil, natural gas or NGLs production. We record sales revenue based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes based on company-measured volume readings. We then adjust our crude oil, natural gas and NGLs sales in subsequent periods based on the data received from our purchasers that reflects actual volumes delivered and prices received. We receive payment for sales one to two months after actual delivery has occurred. The differences in sales estimates and actual sales are recorded one to two months later. Historically, these differences have not been material. If a sale is deemed uncollectible, an allowance for doubtful collection is recorded.

Fair Value of Financial Instruments. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity.

Commodity Derivative Financial Instruments. We measure the fair value of our commodity derivative instruments based on a pricing model that utilizes market-based inputs, including but not limited to the contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates such as the LIBOR curve for a similar duration of each outstanding position, volatility factors and nonperformance risk. Nonperformance risk considers the effect of our credit standing on the fair value of commodity derivative liabilities and the effect of our counterparties' credit standings on the fair value of commodity derivative assets. Both inputs to the model are based on published credit default swap rates and the duration of each outstanding commodity derivative position.

We validate our fair value measurement through the review of counterparty statements and other supporting documentation, the determination that the source of the inputs is valid, the corroboration of the original source of inputs through access to multiple quotes, if available, or other information and monitoring changes in valuation methods and assumptions.

Net settlements on our commodity derivative instruments are initially recorded to accounts receivable or payable, as applicable, and may not be received from or paid to counterparties to our commodity derivative contracts within the same accounting period. Such settlements typically occur the month following the maturity of the commodity derivative instrument. We have evaluated the credit risk of the counterparties holding our commodity derivative assets, which are primarily financial institutions who are also major lenders in our revolving credit facility, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding commodity derivative position. Based on our evaluation, we have determined that the potential impact of nonperformance of our counterparties on the fair value of our commodity derivative instruments is not significant.

Deferred Income Tax Asset Valuation Allowance. Deferred income tax assets are recognized for deductible temporary differences, net operating loss carry-forwards and credit carry-forwards if it is more likely than not that the tax benefits will be realized. To the extent a deferred tax asset is not expected to be realized under the preceding criteria, we establish a valuation allowance. The factors which we consider in assessing whether we will realize the value of deferred income tax assets involve judgments and estimates of both amount and timing. The judgments used in applying these policies are based on our evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

Accounting for Business Combinations. We utilize the purchase method to account for acquisitions of businesses and assets. The value of the purchase consideration takes into account the degree to which the consideration is objective and measurable such as cash consideration paid to a seller. With the issuance of equity, restrictions upon the sale of the issued stock are taken into consideration. Pursuant to purchase method accounting, we allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. The purchase price allocations are based on appraisals, discounted cash flows, quoted market prices and estimates by management. When appropriate, we review comparable purchases and sales of crude oil and natural gas properties within the same regions and use that data as a basis for fair market value as such sales represent the amount at which a willing buyer and seller would enter into an exchange for such properties.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved developed producing, proved developed non-producing, proved undeveloped and unproved crude oil and natural gas properties and other non-crude oil and natural gas properties. To estimate the fair values of these properties, we prepare estimates of crude oil and natural gas reserves. We estimate future prices by using the applicable forward pricing strip to apply to our estimate of reserve quantities acquired, and estimates of future operating and development costs to arrive at an estimate of future net revenues. For estimated proved reserves, the future net revenues are discounted using a market-based weighted-average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted-average cost of capital rate is subject to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, we reduce the discounted future net revenues of probable and possible reserves by additional risk-weighting factors. Additionally, for acquisitions with significant unproved properties, we complete an analysis of comparable purchased properties to determine an estimation of fair value.

If applicable, we record deferred taxes for any differences between the assigned values and tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Acreage Exchanges. From time to time, we enter into acreage exchanges in order to consolidate our core acreage positions, enabling us to have more control over the timing of development activities, achieve higher working interests and providing us the ability to drill longer lateral length wells within those core areas. We account for our nonmonetary acreage exchanges of non-producing interests and unproved mineral leases in accordance with the guidance prescribed by Accounting Standards Codification 845, Nonmonetary Transactions. For those exchanges that lack commercial substance, we record the acreage received at the net carrying value of the acreage surrendered to obtain it. For those acreage exchanges that are deemed to have commercial substance, we record the acreage received at fair value, with a related gain or loss recognized in earnings, in accordance with Accounting Standards Codification 820, Fair Value Measurement.

Recent Accounting Standards

See the footnote titled Summary of Significant Accounting Policies - Recently Adopted Accounting Standards to our consolidated financial statements included elsewhere in this report.

Reconciliation of Non-U.S. GAAP Financial Measures

We use "adjusted cash flows from operations," "adjusted net income (loss)" and "adjusted EBITDAX," non-U.S. GAAP financial measures, for internal management reporting, when evaluating period-to-period changes and, in some cases, providing public guidance on possible future results. These measures are not measures of financial performance under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss) or cash flows from operations, investing or financing activities and should not be viewed as liquidity measures or indicators of cash flows reported in accordance with U.S. GAAP. The non-U.S. GAAP financial measures that we use may not be comparable to similarly titled measures reported by other companies. Also, in the future, we may disclose different non-U.S. GAAP financial measures in order to help our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

Adjusted cash flows from operations. We define adjusted cash flows from operations as the cash flows earned or incurred from operating activities, without regard to changes in operating assets and liabilities. We believe it is important to consider adjusted cash flows from operations, as well as cash flows from operations, as we believe it often provides more transparency into what drives the changes in our operating trends, such as production, prices, operating costs and related operational factors, without regard to whether the related asset or liability was received or paid during the same period. We also use this measure because the timing of cash received from our assets, cash paid to obtain an asset or payment of our obligations has generally been a timing issue from one period to the next as we have not had significant accounts receivable collection problems, nor been unable to purchase assets or pay our obligations.

Adjusted net income (loss). We define adjusted net income (loss) as net income (loss), plus loss on commodity derivatives, less gain on commodity derivatives and net settlements on commodity derivatives, each adjusted for tax effect. We believe it is important to consider adjusted net income (loss), as well as net income (loss). We believe this measure often provides more transparency into our operating trends, such as production, prices, operating costs, net settlements from derivatives and related factors, without regard to changes in our net income (loss) from our mark-to-market adjustments resulting from net changes in the fair value of unsettled derivatives. Additionally, other items which are not indicative of future results may be excluded to clearly identify operating trends.

Adjusted EBITDAX. We define adjusted EBITDAX as net income (loss), plus loss on commodity derivatives, interest expense, net of interest income, income taxes, impairment of properties and equipment, exploration, geologic and geophysical expense, depreciation, depletion and amortization expense, accretion of asset retirement obligations and non-cash stock-based compensation, less gain on commodity derivatives and net settlements on commodity derivatives. Adjusted EBITDAX is not a measure of financial performance or liquidity under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss), and should not be considered an indicator of cash flows reported in accordance with U.S. GAAP. Adjusted EBITDAX includes certain non-cash costs incurred by us and does not take into account changes in operating assets and liabilities. Other companies in our industry may calculate adjusted EBITDAX differently than we do, limiting its usefulness as a comparative measure. We believe adjusted EBITDAX is relevant because it is a measure of our operational and financial performance, as well as a measure of our liquidity, and is used by our management, investors, commercial banks, research analysts, and others to analyze such things as:

- operating performance and return on capital as compared to our peers;
- financial performance of our assets and our valuation without regard to financing methods, capital structure or historical cost basis;
- our ability to generate sufficient cash to service our debt obligations; and
- the viability of acquisition opportunities and capital expenditure projects, including the related rate of return.

PV-10. We define PV-10 as the estimated present value of the future net cash flows from our proved reserves before income taxes, discounted using a 10 percent discount rate. We believe that PV-10 provides useful information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies. We believe that PV-10 is relevant and useful for evaluating the relative monetary significance of our reserves. Professional analysts, investors and other users of our financial statements may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable in evaluating us and our reserves. PV-10 is not intended to represent the current market value of our estimated reserves.

The following table presents a reconciliation of our non-U.S. GAAP financial measures to its most comparable U.S. GAAP measure:

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Adjusted cash flows from operations:			
Net cash from operating activities	$889.3	$597.8	$486.3
Changes in assets and liabilities	(80.9)	(15.7)	(19.5)
Adjusted cash flows from operations	$808.4	$582.1	$466.8
Adjusted net loss:			
Net income (loss)	$2.0	$(127.5)	$(245.9)
(Gain) loss on commodity derivative instruments	(145.2)	3.9	125.7
Net settlements on commodity derivative instruments	(115.5)	13.3	208.1
Tax effect of above adjustments	62.4	(4.1)	(124.9)
Adjusted net loss	$(196.3)	$(114.4)	$(37.0)
Net income (loss) to adjusted EBITDAX:			
Net income (loss)	$2.0	$(127.5)	$(245.9)
(Gain) loss on commodity derivative instruments	(145.2)	3.9	125.7
Net settlements on commodity derivative instruments	(115.5)	13.3	208.1
Non-cash stock-based compensation	21.8	19.4	19.5
Interest expense, net	70.3	76.4	61.0
Income tax expense (benefit)	5.4	(211.9)	(147.2)
Impairment of properties and equipment	458.4	285.9	10.0
Impairment of goodwill	—	75.1	—
Exploration, geologic and geophysical expense	6.2	47.3	4.7
Depreciation, depletion and amortization	559.8	469.1	416.9
Accretion of asset retirement obligations	5.1	6.4	7.0
Loss on extinguishment of debt	—	24.7	—
Adjusted EBITDAX	$868.3	$682.1	$459.8
Cash from operating activities to adjusted EBITDAX:			
Net cash from operating activities	$889.3	$597.8	$486.3
Interest expense, net	70.3	76.4	61.0
Amortization of debt discount and issuance costs	(12.8)	(12.9)	(16.2)
Gain (loss) on sale of properties and equipment	(0.4)	0.7	—
Exploration, geologic and geophysical expense	6.2	47.3	4.7
Exploratory dry hole expense	(0.1)	(41.3)	—
Other	(3.3)	29.8	(56.5)
Changes in assets and liabilities	(80.9)	(15.7)	(19.5)
Adjusted EBITDAX	$868.3	$682.1	$459.8
PV-10:			
PV-10	$5,321.3	$3,212.0	$1,675.0
Present value of estimated future income tax discounted at 10%	(873.6)	(331.9)	(254.4)
Standardized measure of discounted future net cash flows	$4,447.7	$2,880.1	$1,420.6

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rate risks, commodity price risk and credit risk. We have established risk management processes to monitor and manage these market risks.

Interest Rate Risk

Changes in interest rates affect the amount of interest we earn on our interest bearing cash and cash equivalents and the interest we pay on borrowings under our revolving credit facility. Our 2021 Convertible Notes, 2024 Senior Notes and 2026 Senior Notes have fixed rates and, therefore, near-term changes in interest rates do not expose us to risk of earnings or cash flow loss; however, near-term changes in interest rates may affect the fair value of our fixed-rate debt.

As of December 31, 2018, our interest-bearing deposit accounts included money market accounts and checking accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of December 31, 2018 was $0.6 million, with a weighted-average interest rate of one percent. Based on a sensitivity analysis of our interest bearing deposits as of December 31, 2018 and assuming we had $0.6 million outstanding throughout the period, we estimate that a one percent increase in interest rates would not have a material impact on interest income for the twelve months ended December 31, 2018.

As of December 31, 2018, we had $32.5 million outstanding balance on our revolving credit facility. If market interest rates would have decreased by one percent, our interest expense for the twelve months ended December 31, 2018 would have decreased by approximately $0.3 million. If market interest rates would have increased by one percent, our interest expense for the twelve months ended December 31, 2018 would have increased by approximately $0.2 million.

Commodity Price Risk

We are exposed to the potential risk of loss from adverse changes in the market price of crude oil, natural gas and NGLs. Pursuant to established policies and procedures, we manage a portion of the risks associated with these market fluctuations using commodity derivative instruments. These instruments help us predict with greater certainty the effective crude oil, natural gas and propane prices we will receive for our hedged production. We believe that our commodity derivative policies and procedures are effective in achieving our risk management objectives.

Our realized prices vary regionally based on local market differentials and our transportation agreements. The following table presents average market index prices for crude oil and natural gas for the periods identified, as well as the average sales prices we realized for our crude oil, natural gas and NGLs production:

	Year Ended December 31,	
	2018	2017
Average NYMEX Index Price:		
Crude oil (per Bbl)		
NYMEX	$64.77	$50.95
Natural gas (per MMBtu)		
NYMEX	$3.09	$3.11

Average Sales Price Realized:		
Excluding net settlements on commodity derivatives		
Crude oil (per Bbl)	$61.19	$48.45
Natural gas (per Mcf)	1.85	2.21
NGLs (per Bbl)	22.14	18.59

Based on a sensitivity analysis as of December 31, 2018, we estimate that a 10 percent increase in natural gas, crude oil prices and the propane portion of NGLs prices, inclusive of basis, over the entire period for which we have commodity derivatives in place would have resulted in a decrease in the fair value of our derivative positions of $63.1 million, whereas a 10 percent decrease in prices would have resulted in an increase in fair value of $63.9 million.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When exposed to significant credit risk, we analyze the counterparties’ financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We monitor the creditworthiness of significant counterparties through our credit committee, which utilizes a number of qualitative and quantitative tools to assess credit risk and takes mitigative actions if deemed necessary. While we believe that our credit risk analysis and monitoring procedures are reasonable, no amount of analysis can assure financial performance by our counterparties.

Our oil and gas exploration and production business's crude oil, natural gas and NGLs sales are concentrated with a few predominately large customers. This concentrates our credit risk exposure with a small number of large customers.

Amounts due to our gas marketing business are from a diverse group of entities. The underlying operations of these entities are geographically concentrated in the same region, which increases the credit risk associated with this business. As natural gas prices continue to remain depressed, certain third-party producers committed to providing natural gas to our gas marketing business continue to experience financial distress, which has led to certain contractual defaults and litigation; however, to date, we have had no material counterparty default losses. We have initiated several legal actions for breach of contract and collection claims against certain third-party producers that are delinquent in their payment obligations. We expect this trend to continue for this business segment.

We primarily use financial institutions which are lenders in our revolving credit facility as counterparties for our derivative financial instruments. Disruption in the credit markets, changes in commodity prices and other factors may have a significant adverse impact on a number of financial institutions. To date, we have had no material counterparty default losses from our commodity derivative financial instruments. See the footnote titled Commodity Derivative Financial Instruments to our consolidated financial statements included elsewhere in this report for more detail on our commodity derivative financial instruments.

Disclosure of Limitations

Because the information above included only those exposures that existed at December 31, 2018, it does not consider those exposures or positions which could arise after that date. Our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time and interest rates and commodity prices at the time.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements, Financial Statement Schedule and Supplemental Information

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PDC Energy, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of PDC Energy, Inc. and its subsidiaries (the “Company”) as of December 31, 2018 and 2017, and the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2018, including the related notes and financial statement schedule listed in the accompanying index (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2018 based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO because material weaknesses in internal control over financial reporting existed as of that date related to not maintaining a sufficient complement of personnel within the Land Department as a result of an increased volume of leases, which contributed to the ineffective design and maintenance of controls to verify the completeness and accuracy of land administrative records associated with unproved leases.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weaknesses referred to above are described in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. We considered these material weaknesses in determining the nature, timing, and extent of audit tests applied in our audit of the 2018 consolidated financial statements, and our opinion regarding the effectiveness of the Company’s internal control over financial reporting does not affect our opinion on those consolidated financial statements.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which it accounts for revenues from contracts with customers in 2018.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in management's report referred to above. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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/PricewaterhouseCoopers LLP

Denver, Colorado
February 27, 2019

We have served as the Company's auditor since 2007.

PDC ENERGY, INC.
Consolidated Balance Sheets
(in thousands, except share and per share data)

As of December 31,	2018	2017
Assets		
Current assets:		
Cash and cash equivalents	$1,398	$180,675
Accounts receivable, net	181,434	197,598
Fair value of derivatives	84,492	14,338
Prepaid expenses and other current assets	7,136	8,613
Total current assets	274,460	401,224
Properties and equipment, net	4,002,862	3,933,467
Assets held-for-sale	140,705	40,583
Fair value of derivatives	93,722	—
Other assets	32,396	45,116
Total Assets	$4,544,145	$4,420,390
Liabilities and Stockholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$181,864	$150,067
Production tax liability	60,719	37,654
Fair value of derivatives	3,364	79,302
Funds held for distribution	105,784	95,811
Accrued interest payable	14,150	11,815
Other accrued expenses	75,133	42,987
Total current liabilities	441,014	417,636
Long-term debt	1,194,876	1,151,932
Deferred income taxes	198,096	191,992
Asset retirement obligations	85,312	71,006
Liabilities held-for-sale	4,111	499
Fair value of derivatives	1,364	22,343
Other liabilities	92,664	57,333
Total liabilities	2,017,437	1,912,741
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 66,148,609 and 65,955,080 issued as of December 31, 2018 and 2017, respectively	661	659
Additional paid-in capital	2,519,423	2,503,294
Retained earnings	8,727	6,704
Treasury shares - at cost, 45,220 and 55,927 as of December 31, 2018 and 2017, respectively	(2,103)	(3,008)
Total stockholders' equity	2,526,708	2,507,649
Total Liabilities and Stockholders' Equity	$4,544,145	$4,420,390

See accompanying Notes to Consolidated Financial Statements

PDC ENERGY, INC.
Consolidated Statements of Operations
(in thousands, except per share data)

Year Ended December 31,	2018	2017	2016
Revenues			
Crude oil, natural gas and NGLs sales	$1,389,961	$913,084	$497,353
Commodity price risk management gain (loss), net	145,237	(3,936)	(125,681)
Other income	13,461	12,468	11,243
Total revenues	1,548,659	921,616	382,915
Costs, expenses and other			
Lease operating expenses	130,957	89,641	59,950
Production taxes	90,357	60,717	31,410
Transportation, gathering and processing expenses	37,403	33,220	18,415
Exploration, geologic and geophysical expense	6,204	47,334	4,669
Impairment of properties and equipment	458,397	285,887	9,973
Impairment of goodwill	—	75,121	—
General and administrative expense	170,504	120,370	112,470
Depreciation, depletion and amortization	559,793	469,084	416,874
Accretion of asset retirement obligations	5,075	6,306	7,080
(Gain) loss on sale of properties and equipment	394	(766)	(43)
Provision for uncollectible notes receivable	—	(40,203)	44,038
Other expenses	11,829	13,157	10,193
Total costs, expenses and other	1,470,913	1,159,868	715,029
Income (loss) from operations	77,746	(238,252)	(332,114)
Loss on extinguishment of debt	—	(24,747)	—
Interest expense	(70,730)	(78,694)	(61,972)
Interest income	413	2,261	963
Income (loss) before income taxes	7,429	(339,432)	(393,123)
Income tax (expense) benefit	(5,406)	211,928	147,195
Net income (loss)	$2,023	$(127,504)	$(245,928)
Earnings per share:			
Basic	$0.03	$(1.94)	$(5.01)
Diluted	$0.03	$(1.94)	$(5.01)
Weighted-average common shares outstanding:			
Basic	66,059	65,837	49,052
Diluted	66,303	65,837	49,052

See accompanying Notes to Consolidated Financial Statements

PDC ENERGY, INC.
Consolidated Statements of Cash Flows
(in thousands)

Year Ended December 31,	2018	2017	2016
Cash flows from operating activities:			
Net income (loss)	$ 2,023	$(127,504)	$(245,928)
Adjustments to net income (loss) to reconcile to net cash from operating activities:			
Net change in fair value of unsettled commodity derivatives	(260,775)	17,260	333,770
Depreciation, depletion and amortization	559,793	469,084	416,874
Impairment of properties and equipment	458,397	285,887	9,973
Impairment of goodwill	—	75,121	—
Exploratory dry hole costs	113	41,297	—
Provision for uncollectible notes receivable	—	(40,203)	44,038
Loss on extinguishment of debt	—	24,747	—
Accretion of asset retirement obligations	5,075	6,306	7,080
Non-cash stock-based compensation	21,782	19,353	19,502
(Gain) loss on sale of properties and equipment	394	(766)	(43)
Amortization of debt discount and issuance costs	12,769	12,907	16,167
Deferred income taxes	6,105	(203,685)	(137,249)
Other	2,763	2,265	2,603
Total adjustments to net income (loss) to reconcile to net cash from operating activities:	806,416	709,573	712,715
Changes in assets and liabilities:			
Accounts receivable	12,025	(60,546)	(32,627)
Other assets	(81)	3,364	2,303
Production tax liability	35,225	31,316	9,223
Accounts payable and accrued expenses	16,261	31,378	(162)
Funds held for future distribution	9,973	24,472	36,510
Asset retirement obligations	(13,341)	(10,176)	(4,109)
Other liabilities	20,801	(4,064)	8,338
Total changes in assets and liabilities	80,863	15,744	19,476
Net cash from operating activities	889,302	597,813	486,263
Cash flows from investing activities:			
Capital expenditures for development of crude oil and natural gas properties	(946,350)	(737,208)	(436,884)
Capital expenditures for other properties and equipment	(11,055)	(5,094)	(3,464)
Acquisition of crude oil and natural gas properties	(180,026)	(15,628)	(1,073,723)
Proceeds from sale of properties and equipment	3,562	9,991	4,945
Proceeds from divestiture	44,693	—	—
Sale of promissory note	—	40,203	—
Restricted cash	1,249	(9,250)	—
Sale of short-term investments	—	49,890	—
Purchase of short-term investments	—	(49,890)	—
Net cash from investing activities	(1,087,927)	(716,986)	(1,509,126)
Cash flows from financing activities:			
Proceeds from revolving credit facility	1,072,500	—	85,000
Repayment of revolving credit facility	(1,040,000)	—	(122,000)
Proceeds from issuance of equity, net of issuance costs	—	—	855,074

Proceeds from issuance of senior notes	—	592,366	392,172
Proceeds from issuance of convertible senior notes	—	—	193,935
Redemption of senior notes	—	(519,375)	—
Redemption of convertible notes	—	—	(115,000)
Payment of debt issuance costs	(7,704)	(50)	(15,556)
Purchase of treasury shares	(5,147)	(6,672)	(6,935)
Other	(1,550)	(1,271)	(577)
Net cash from financing activities	18,099	64,998	1,266,113
Net change in cash, cash equivalents and restricted cash	(180,526)	(54,175)	243,250
Cash, cash equivalents and restricted cash, beginning of year	189,925	244,100	850
Cash, cash equivalents and restricted cash, end of year	$ 9,399	$ 189,925	$ 244,100

See accompanying Notes to Consolidated Financial Statements

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PDC ENERGY, INC.
Consolidated Statements of Equity
(in thousands, except share data)

	Common Stock			Treasury Stock			
	Shares	Amount	Additional Paid-in Capital	Shares	Amount	Retained Earnings	Total Stockholders' Equity
Balances, January 1, 2016	40,174,776	$ 402	$ 907,382	(20,220)	$ (1,009)	$ 380,422	$ 1,287,197
Net loss	—	—	—	—	—	(245,928)	(245,928)
Issuance pursuant to acquisition	9,386,768	94	690,608	—	—	—	690,702
Issuance pursuant to sale of equity	15,007,500	150	854,933	—	—	—	855,083
Convertible debt discount, net of issuance costs and tax	—	—	23,518	—	—	—	23,518
Purchase of treasury shares	—	—	—	(116,085)	(6,935)	—	(6,935)
Issuance pursuant to note conversion	792,406	8	(8)	—	—	—	—
Issuance of treasury shares	(114,697)	—	(6,661)	114,697	6,661	—	—
Non-employee directors' deferred compensation plan	—	—	—	(7,155)	(385)	—	(385)
Issuance of stock awards, net of forfeitures	411,731	3	(3)	—	—	—	—
Exercise of stock options	46,084	—	—	—	—	—	—
Stock-based compensation expense	—	—	19,502	—	—	—	19,502
Other	—	—	286	—	—	(286)	—
Balances, December 31, 2016	65,704,568	$ 657	$ 2,489,557	(28,763)	$ (1,668)	$ 134,208	$ 2,622,754
Net loss	—	—	—	—	—	(127,504)	(127,504)
Purchase of treasury shares	—	—	—	(107,357)	(6,672)	—	(6,672)
Issuance of treasury shares	—		(5,517)	83,228	5,517	—	—
Non-employee directors' deferred compensation plan	—	—	—	(3,035)	(185)	—	(185)
Issuance of stock awards, net of forfeitures	250,512	2	(2)	—	—	—	—
Stock-based compensation expense	—	—	19,353	—	—	—	19,353
Other	—	—	(97)	—	—	—	(97)
Balances, December 31, 2017	65,955,080	$ 659	$ 2,503,294	(55,927)	$ (3,008)	$ 6,704	$ 2,507,649
Net income	—	—	—	—	—	2,023	2,023
Purchase of treasury shares	—	—	—	(102,647)	(5,147)	—	(5,147)
Issuance of treasury shares	—	—	(5,561)	104,068	5,561	—	—
Non-employee directors' deferred compensation plan	—	—	—	9,286	491	—	491
Issuance of stock awards, net of forfeitures	193,529	2	(2)	—	—	—	—
Stock-based compensation expense	—	—	21,782	—	—	—	21,782
Other	—	—	(90)	—	—	—	(90)
Balance, December 31, 2018	66,148,609	$ 661	$ 2,519,423	(45,220)	$ (2,103)	$ 8,727	$ 2,526,708

See accompanying Notes to Consolidated Financial Statements

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. ("PDC", the "Company," "we," "us," or "our") is a domestic independent exploration and production company that acquires, explores and develops properties for the production of crude oil, natural gas and NGLs, with operations in the Wattenberg Field in Colorado and the Delaware Basin in Texas. Our operations in the Wattenberg Field are focused in the rural areas of the horizontal Niobrara and Codell plays and our Delaware Basin operations are primarily focused in the Wolfcamp zones. We previously operated properties in the Utica Shale in Southeastern Ohio; however, we divested these properties during the first quarter of 2018. As of December 31, 2018, we owned an interest in approximately 2,900 productive gross wells. We are engaged in two operating segments: our oil and gas exploration and production segment and our gas marketing segment. Our gas marketing segment does not meet the quantitative thresholds to require disclosure as a separate reportable segment. All of our material operations are attributable to our exploration and production business; therefore, all of our operations are presented as a single segment for all periods presented.

The audited consolidated financial statements include the accounts of PDC, our wholly-owned subsidiaries and our proportionate share of our affiliated partnerships. All intercompany accounts and transactions have been eliminated in consolidation.

The preparation of our consolidated financial statements in accordance with U.S. GAAP requires us to make estimates and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. Actual results could differ from those estimates. Estimates which are particularly significant to our consolidated financial statements include estimates of crude oil, natural gas and NGLs sales revenue; crude oil, natural gas and NGLs reserves; estimates of unpaid revenues and unbilled costs; future cash flows from crude oil and natural gas properties; valuation of commodity derivative instruments; exploratory dry hole costs; impairment of proved and unproved properties; impairment of goodwill; valuation and allocations of purchased and exchanged businesses and assets; estimates of fair value of our fixed rate debt instruments; and valuation of deferred income tax assets.

Certain immaterial reclassifications have been made to our prior period balance sheet to conform to the current period presentation. The reclassifications had no impact on previously reported results.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash Equivalents. We consider all highly liquid investments with original maturities of three months or less to be cash equivalents.
Commodity Derivative Financial Instruments. We are exposed to the effect of market fluctuations in the prices of crude oil, natural gas and NGLs. We employ established policies and procedures to manage a portion of the risks associated with these market fluctuations using commodity derivative instruments. Our policy and our revolving credit facility prohibit the use of crude oil and natural gas derivative instruments for speculative purposes.

Derivative assets and liabilities are recorded on our consolidated balance sheets at fair value. We have elected not to designate any of our commodity derivative instruments as cash flow hedges. Accordingly, changes in the fair value of our commodity derivative instruments are recorded in the consolidated statements of operations. We have elected the normal purchase, normal sale exception for our crude oil and natural gas contracts; therefore, the effects of these contracts are not included in our derivative assets and liabilities. Classification of net settlements resulting from maturities and changes in fair value of unsettled commodity derivatives depends on the purpose of issuing or holding the derivative. Net settlements and changes in the fair value of commodity derivative instruments related to our Oil and Gas Exploration and Production segment are recorded in commodity price risk management, net. Net settlements and changes in the fair value of commodity derivative instruments related to our Gas Marketing segment are recorded in other income and other expenses. The consolidated statements of cash flows reflects the net settlement of commodity derivative instruments in operating cash flows.

The calculation of the commodity derivative instrument's fair value is performed internally and, while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values.

Properties and Equipment. Significant accounting polices related to our properties and equipment are discussed below.

Crude Oil and Natural Gas Properties. We account for our crude oil and natural gas properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depreciated or depleted by the unit-of-production method, based on estimated proved developed producing reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved reserves. We have determined that we have two unit-of-production fields: the Wattenberg Field and the Delaware Basin. In making these conclusions we consider the geographic concentration, operating similarities within the areas, geologic considerations and common cost environments in these areas. We calculate quarterly depreciation, depletion and amortization ("DD&A") expense by using our estimated prior period-end reserves as the denominator, with the exception of our fourth quarter where we use the year-end reserve estimate adjusted for fourth quarter production. Upon the sale or retirement of significant portions of or complete fields of depreciable or depletable property, the net book value thereof, less proceeds or salvage value, is recognized in the consolidated statement of operations as a gain or loss. Upon the sale of individual wells or an insignificant portion of a field, the proceeds are credited to accumulated DD&A.

Exploration costs, including geologic and geophysical expenses, seismic costs on unproved leaseholds and delay rentals are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized, but charged to expense if the well is determined to be economically nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as we have found a sufficient quantity of reserves to justify completion as a producing well, we are making sufficient progress assessing our reserves and economic and operating viability or we have not made sufficient progress to allow for final determination of productivity. If an in-progress exploratory well is found to be economically unsuccessful prior to the issuance of the financial statements, the costs incurred prior to the end of the reporting period are charged to exploration expense. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the costs associated with the well are classified as suspended well costs until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time we are able to make a final determination of a well's productive status, the well is removed from suspended well status and the resulting accounting treatment is recorded.

Proved Property Impairment. Annually, or upon a triggering event, we assess our producing crude oil and natural gas properties for possible impairment by comparing carrying value to estimated undiscounted future net cash flows on a field-by-field basis using estimated production and prices at which we reasonably estimate the commodities will be sold. The estimates of future prices may differ from current market prices of crude oil, natural gas and NGLs. Certain events, including but not limited to downward revisions in estimates of our reserve quantities, expectations of falling commodity prices or rising operating costs, could result in a triggering event, and therefore a possible impairment of our proved crude oil and natural gas properties. If carrying values exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a discounted future cash flows analysis. The impairment recorded is the amount by which the carrying values exceed fair value. Impairments are included in the consolidated statements of operations line item impairment of properties and equipment, with a corresponding impact on accumulated DD&A.

Unproved Property Impairment. Acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to expense. Unproved crude oil and natural gas properties with individually significant acquisition costs are periodically assessed for impairment. Unproved crude oil and natural gas properties which are not individually significant are amortized by field, based on our historical experience, acquisition dates and average lease terms. Impairment and amortization charges related to unproved crude oil and natural gas properties are charged to the consolidated statements of operations line item impairment of properties and equipment.

Other Property and Equipment. Other property and equipment such as pipelines, vehicles, facilities, office furniture and equipment, buildings and computer hardware and software is carried at cost. Depreciation is provided principally on the straight-line method over the assets' estimated useful lives, which range from two to 35 years. We review these long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying value of the asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying value of the asset exceeds the estimated future cash flows, an impairment charge is recognized in the amount by which the carrying value of the asset exceeds the fair value of the asset. Impairment and amortization charges related to other property and equipment are charged to the consolidated statements of operations line item impairment of properties and equipment.

Maintenance and repair costs on other property and equipment are charged to expense as incurred. Major renewals and improvements are capitalized and depreciated over the remaining useful life of the asset. Upon the sale or other disposition of assets, the cost and related accumulated DD&A are removed, the proceeds are applied and any resulting gain or loss is reflected in income. Total depreciation expense related to other property and equipment was $8.5 million, $6.6 million and $3.8 million in 2018, 2017 and 2016, respectively.

Internal-Use Software. Certain internal-use software costs incurred during the development stage are capitalized. The development stage generally includes software design, configuration, testing and installation activities. Training and maintenance costs are expenses as incurred, while upgrades and enhancements are capitalized if it is probable that such expenditures will result in additional functionality. Capitalized internal-use software costs are depreciated over the estimated useful life of the underlying project on a straight-line basis upon completion of the project. As of December 31, 2018, capitalized costs for internal-use software were not material. We did not have any capitalized internal-use software costs at December 31, 2017.

Capitalized Interest. Interest costs are capitalized as part of the historical cost of acquiring assets. Investments in unproved crude oil and natural gas properties and major development projects, on which DD&A expense is not currently recorded and on which exploration or development activities are in progress, qualify for capitalization of interest. Major construction projects also qualify for interest capitalization until the asset is ready to be placed into service. Capitalized interest is calculated by multiplying our weighted-average interest rate on our outstanding debt by the qualifying costs. Interest capitalized may not exceed gross interest expense for the period. As the qualifying asset is placed into service, we begin amortizing the related capitalized interest over the useful life of the asset. Capitalized interest totaled $9.2 million, $5.0 million and $4.5 million in 2018, 2017 and 2016, respectively.

Assets Held-for-Sale. Assets held-for-sale are valued at the lower of their carrying amount or estimated fair value, less costs to sell. If the carrying amount of the assets exceeds their estimated fair value, an impairment loss is recognized. Fair values are estimated using accepted valuation techniques, such as a discounted cash flow model, earnings multiples or indicative bids, when available. Management considers historical experience and all available information at the time the estimates are made; however, the fair value that is ultimately realized upon the sale of the assets to be divested may differ from the estimated fair values reflected in the consolidated financial statements. DD&A expense is not recorded on assets once they are classified as held-for-sale. Assets classified as held-for-sale are expected to be disposed of within one year.

Production Tax Liability. Production tax liability represents estimated taxes, primarily severance, ad valorem and property taxes, to be paid to the states and counties in which we produce crude oil, natural gas and NGLs. These taxes are expensed and included in the statements of operations line item production taxes. The long-term portion of the production tax liability is included in other liabilities on the consolidated balance sheets and was $61.3 million and $50.5 million in December 31, 2018 and 2017, respectively.

Income Taxes. We account for income taxes under the asset and liability method. We recognize deferred tax assets and liabilities for the future tax consequences attributable to operating loss and credit carryforwards and differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. If we determine that it is more likely than not that some portion or all of the deferred tax assets will not be realized, we record a valuation allowance, thereby reducing the deferred tax assets to what we consider realizable.

Debt Issuance Costs. Debt issuance costs are capitalized and amortized over the life of the respective borrowings using the effective interest method. Debt issuance costs for the 2021 Convertible Notes, the 2024 Senior Notes and the 2026 Senior Notes are included in long-term debt on the consolidated balance sheets and the debt issuance costs for the revolving credit facility are included in other assets on the consolidated balance sheets.

Asset Retirement Obligations. We account for asset retirement obligations by recording the fair value of our plugging and abandonment obligations when incurred, which is at the time the related well is completed. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the associated long-lived asset by the same amount as the liability. Over time, the liability is accreted for the change in the present value. The initial capitalized cost, net of salvage value, is depleted over the useful life of the related asset through a charge to DD&A expense. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from, among other things, changes in retirement costs or the estimated timing of settling asset retirement obligations.

Treasury Shares. We record treasury share purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as a reduction in shareholders' equity in the consolidated balance sheets. When we retire treasury shares, we charge any excess of cost over the par value to additional paid-in-capital ("APIC"), to the extent we have amounts in APIC, with any remaining excess cost being charged to retained earnings.

Revenue Recognition. Crude oil, natural gas and NGLs revenues are recognized when we have transferred control of crude oil, natural gas, or NGLs production to the purchaser. We consider the transfer of control to have occurred when the purchaser has the ability to direct the use of, and obtain substantially all of the remaining benefits from, the crude oil, natural gas or NGLs production. We record sales revenue based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes based on company-measured volume readings. We then adjust our crude oil, natural gas and NGLs sales in subsequent periods based on the data received from our purchasers that reflects actual volumes delivered and prices received. We receive payment for sales one to two months after actual delivery has occurred. The differences in sales estimates and actual sales are recorded one to two months later. Historically, these differences have not been material. We account for natural gas imbalances using the sales method. For 2018, 2017 and 2016, the impact of any natural gas imbalances was not significant. If a sale is deemed uncollectible, an allowance for doubtful collection is recorded.

Our crude oil, natural gas and NGLs sales are recorded using either the “net-back” or "gross" method of accounting, depending upon the related agreement. We use the net-back method when control of the crude oil, natural gas, or NGLs has been transferred to the purchasers of these commodities that are providing transportation, gathering or processing services. In these situations, the purchaser pays us proceeds based on a percent of the proceeds or have fixed our sales price at index less specified deductions. The net-back method results in the recognition of a net sales price that is lower than the index for which the production is based because the operating costs and profit of the midstream facilities are embedded in the net price we are paid.

We use the gross method of accounting when control of the crude oil, natural gas, or NGLs is not transferred to the purchaser and the purchaser does not provide transportation, gathering, or processing services as a function of the price we receive. Rather, we contract separately with midstream providers for the applicable transport and processing on a per unit basis. Under this method, we recognize revenues based on the gross selling price and recognize transportation, gathering and processing expenses.

Credit Risk and Allowance for Doubtful Accounts. Inherent to our industry is the concentration of crude oil, natural gas and NGLs sales to a limited number of customers. This concentration has the potential to impact our overall exposure to credit risk in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. We record an allowance for doubtful accounts representing our best estimate of probable losses from our existing accounts receivable. In making our estimate, we consider, among other things, our historical write-offs and the overall creditworthiness of our customers. Further, consideration is given to well production data for receivables related to well operations.

Accounting for Business Combinations. We utilize the purchase method to account for acquisitions of businesses. Pursuant to purchase method accounting, we allocate the cost of the acquisition to assets acquired and liabilities assumed based upon respective fair values as of the acquisition date. The purchase price allocations are based upon appraisals, discounted cash flows, quoted market prices and estimates by management, which are Level 3 inputs. When appropriate, we review comparable purchases and sales of crude oil and natural gas properties within the same regions and use that data as a basis for fair market value; for example, the amount at which a willing buyer and seller would enter into an exchange for such properties.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved developed producing, proved developed non-producing, proved undeveloped, unproved crude oil and natural gas properties and other non-crude oil and natural gas properties. To estimate the fair value of these properties, we prepare estimates of crude oil and natural gas reserves. We estimate future prices by using the applicable forward pricing strip to apply to our estimate of reserve quantities acquired and estimates of future operating and development costs to arrive at an estimate of future net revenues. For estimated proved reserves, the future net revenues are discounted using a market-based weighted-average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted-average cost of capital rate is subject to additional project-specific risk factors. To compensate for the inherent risk of estimating and valuing unproved properties, we reduce the discounted future net revenues of probable and possible reserves by additional risk-weighting factors. Additionally, for acquisitions with significant unproved properties, we complete an analysis of comparable purchased properties to determine an estimation of fair value.

If applicable, we record deferred taxes for any differences between the assigned values and tax basis of assets and liabilities, except goodwill. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Acreage Exchanges. From time to time, we enter into acreage exchanges in order to consolidate our core acreage positions, enabling us to have more control over the timing of development activities, achieve higher working interests and providing us the ability to drill longer lateral length wells within those core areas. We account for our nonmonetary acreage exchanges of non-producing interests and unproved mineral leases in accordance with the guidance prescribed by Accounting Standards Codification 845, Nonmonetary Transactions. For those exchanges that lack commercial substance, we record the acreage received at the net carrying value of the acreage surrendered to obtain it. For those acreage exchanges that are deemed to have commercial substance, we record the acreage received at fair value, with a related gain or loss recognized in earnings, in accordance with Accounting Standards Codification 820, Fair Value Measurement.

Stock-Based Compensation. Stock-based compensation is recognized in our financial statements based on the grant-date fair value of the equity instrument awarded. Stock-based compensation expense is recognized in the financial statements on a straight-line basis over the vesting period for the entire award and we account for forfeitures of stock-based compensation awards as they occur. To the extent compensation cost relates to employees directly involved in crude oil and natural gas exploration and development activities or the development of internal-use software, such amounts may be capitalized to properties and equipment. Amounts not capitalized to properties and equipment are recognized in the related cost and expense line item in the consolidated statements of operations.

Recently Adopted Accounting Standards.

In May 2014, the Financial Accounting Standards Board ("FASB") and the International Accounting Standards Board issued their converged standard on revenue recognition that provides a single, comprehensive model that entities will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The standard outlines a five-step approach to apply the underlying principle: (1) identify the contract with the customer, (2) identify the separate performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to separate performance obligations and (5) recognize revenue when or as each performance obligation is satisfied. We adopted the standard effective January 1, 2018 under the modified retrospective method. In order to evaluate the impact that the adoption of the revenue standard had on our consolidated financial statements, we performed a comprehensive review of our significant revenue streams. The focus of this review included, among other things, the identification of the significant contracts and other arrangements we have with our customers to identify performance obligations and principal versus agent considerations and factors affecting the determination of the transaction price. We also reviewed our current accounting policies, procedures and controls with respect to these contracts and arrangements to determine what changes, if any, would be required by the adoption of the revenue standard. Upon adoption, no adjustment to our opening balance of retained earnings was deemed necessary. See the footnote below titled Revenue Recognition for further details regarding the changes in our revenue recognition resulting from the adoption of this standard.

In November 2016, the FASB issued an accounting update on statements of cash flows to address diversity in practice in the classification and presentation of changes in restricted cash. The accounting update requires that the statement of cash flows explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash or restricted cash equivalents should be included with cash and cash equivalents when reconciling beginning-of-period and end-of-period amounts shown on the statement of cash flows. The guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. Adoption of this standard impacted our consolidated statements of cash flows. The following table provides a reconciliation of cash and cash equivalents and restricted cash reported on the consolidated balance sheets at December 31, 2018 and 2017, which sum to the total of cash, cash equivalents and restricted cash in the consolidated statements of cash flows:

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	December 31, 2018	December 31, 2017
	(in thousands)	
Cash and cash equivalents	$1,398	$ 180,675
Restricted cash	8,001	9,250
Cash, cash equivalents and restricted cash shown in the consolidated statements of cash flows	$9,399	$ 189,925

Restricted cash is included in other assets on the consolidated balance sheets at December 31, 2018 and December 31, 2017. We did not have any cash classified as restricted cash at December 31, 2016.

In August 2018, the FASB issued an accounting update to align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software and hosting arrangements that include an internal-use software license. The guidance is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, with early adoption permitted. We elected to early adopt this standard in the third quarter of 2018. As of December 31, 2018, capitalized costs for internal-use software were not material.

In November 2018, the FASB issued an accounting update and amendments to clarify the interaction between collaborative contractual arrangements and the revenue recognition standard. The amendments in this update specify that transactions between participants in a collaborative arrangement should be accounted for under the revenue recognition standard when the counterparty is a customer and the guidance precludes entities from presenting consideration from a transaction in a collaborative arrangement as revenue from contracts with customers if the counterparty is not a customer for that transaction. The guidance is effective for fiscal years beginning after December 15, 2019 and interim periods within those fiscal periods, with early adoption permitted. We have elected to early adopt this standard in the fourth quarter of 2018. Upon adoption, no adjustment to our opening balance of retained earnings was deemed necessary as adoption of this standard did not have an impact on our consolidated financial statements.

Recently Issued Accounting Standards

In February 2016, the FASB issued an accounting update and subsequent amendments aimed at increasing the transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about related leasing arrangements (the “New Lease Standard”). For leases with terms of more than 12 months, the accounting update requires lessees to recognize a right-of-use ("ROU") asset and lease liability for its right to use the underlying asset and the corresponding lease obligation. Both the ROU asset and corresponding liability will initially be measured at the present value of the future minimum lease payments over the lease term. Subsequent measurement, as well as presentation of expenses and cash flows, will depend upon the classification of the lease as either a finance or operating lease. We will make accounting policy elections to not recognize ROU assets and lease liabilities that arise from short-term leases and to not separate lease and non-lease components for any class of underlying asset, as provided by practical expedients. In January 2018, the FASB also issued an accounting update which provides an optional transition practical expedient for the adoption of the New Lease Standard that if elected, would not require an organization to reconsider accounting for existing land easements that are not accounted for under the previous lease accounting standard. We will elect this practical expedient and accordingly, existing land easements will not be assessed. All new or modified land easements entered into after January 1, 2019 will be evaluated under the New Lease Standard. The New Lease Standard does not apply to leases of mineral rights to explore for or use crude oil and natural gas. We will adopt the New Lease standard and subsequent amendments effective January 1, 2019 under the modified retrospective approach for all active contracts as of

December 31, 2018. Based upon our implementation progress to date, we expect the adoption of the New Lease Standard to result in increases to total assets and total liabilities of approximately $20.0 million at January 1, 2019, with no adjustment to the opening balance of retained earnings.

NOTE 3 - BUSINESS COMBINATIONS

In January 2018, we closed the acquisition of properties from Bayswater Exploration and Production LLC (the "Bayswater Asset Acquisition") for approximately $200.0 million in cash, after post-closing adjustments, including $21.0 million deposited into an escrow account in 2017. The $21.0 million deposit was included in other assets on our December 31, 2017 consolidated balance sheet. We acquired approximately 7,400 net acres, approximately 220 gross drilling locations and 24 operated horizontal wells that were either DUCs or in-process wells at the time of closing.

The final purchase price and allocation of the assets acquired and the liabilities assumed in the acquisition are presented below. Adjustments made subsequent to the preliminary purchase price stem from final settlement of the proceeds from operating activities and additional information we obtained about facts and circumstances that existed at the acquisition date that impact the underlying value of certain assets acquired and liabilities assumed. Such adjustments primarily relate to sales, operating expenses and capital costs from the effective date through closing.

The details of the final purchase price and allocation of the purchase price for the transaction, are presented below (in thousands):

	December 31, 2018
Acquisition costs:	
Cash	$ 168,560
Deposit made in prior period	21,000
Total cash consideration	189,560
Other purchase price adjustments	10,422
Total acquisition costs	$ 199,982
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Assets acquired:	
Current assets	$ 468
Crude oil and natural gas properties - proved	205,834
Other assets	2,796
Total assets acquired	209,098
Liabilities assumed:	
Current liabilities	(4,429)
Asset retirement obligations	(4,687)
Total liabilities assumed	(9,116)
Total identifiable net assets acquired	$ 199,982

This transaction was accounted for under the acquisition method. Accordingly, we conducted assessments of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition were expensed as incurred. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market, and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties include estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows, lease terms and expirations and a market-based weighted-average cost of capital rate. The allocation of the value to the underlying leases also requires significant judgment and is based on a combination of comparable market transactions, the term and conditions associated with the individual leases, our ability and intent to develop specific leases and our initial assessment of the underlying relative value of the leases given our knowledge of the geology at the time of closing. These inputs require significant judgments and estimates by management at the time of the valuation.

The results of operations for the Bayswater Asset Acquisition for the year ended December 31, 2018 have been included in our consolidated financial statements, including approximately $70.8 million of total revenue, $39.3 million of income from operations and $0.59 of diluted earnings per share. Pro forma results of operations for the Bayswater Asset Acquisition showing results as if the acquisition had been completed as of January 1, 2017 would not have been material to our consolidated financial statements for the year ended December 31, 2017.

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NOTE 4 - REVENUE RECOGNITION

On January 1, 2018, we adopted the new accounting standard that was issued by the FASB to provide a single, comprehensive model to determine the measurement of revenue and timing of when it is recognized and all related amendments (the "New Revenue Standard") using the modified retrospective method. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. Based upon our review, we determined that the adoption of the New Revenue Standard would have reduced our crude oil, natural gas and NGLs sales by approximately $11.3 million in 2017 with a corresponding decrease in transportation, gathering and processing expenses and no impact on net earnings. To determine the impact on our crude oil, natural gas and NGLs sales and our transportation, processing and gathering expenses for 2018, we applied the new guidance to contracts that were not completed as of December 31, 2017. We do not expect adoption of the New Revenue Standard to have a significant impact on our net income going forward.

Based on our evaluation of when control of crude oil and natural gas sales are transferred to the customer under the guidance of the New Revenue Standard, certain crude oil sales in the Wattenberg Field that were recognized using the gross method prior to the adoption of the New Revenue Standard will be recognized using the net-back method. In the Delaware Basin, certain crude oil and natural gas sales that were recognized using the gross method prior to the adoption of the New Revenue Standard will be recognized using the net-back method.

As discussed above, we enter into agreements for the sale, transportation, gathering and processing of our production. The terms of these agreements can result in variances in the per unit realized prices that we receive for our crude oil, natural gas and NGLs. For crude oil, the average NYMEX prices are based upon average daily prices throughout each month and, for natural gas, the average NYMEX pricing is based upon first-of-the-month index prices, as in each case this is how the majority of each of these commodities is sold pursuant to terms of the respective sales agreements. For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes.

Disaggregated Revenue. The following table presents crude oil, natural gas and NGLs sales disaggregated by commodity and operating region for 2018, 2017 and 2016 (in thousands):

	Year Ended December 31,		
Revenue by Commodity and Operating Region	2018	2017 (1)	2016 (1)
Crude oil			
Wattenberg Field	$783,158	$529,562	$329,168
Delaware Basin	252,107	82,677	3,918
Utica Shale (2)	2,696	12,814	15,769
Total	$1,037,961	$625,053	$348,855
Natural gas			
Wattenberg Field	$130,073	$131,792	$86,633
Delaware Basin	32,010	21,251	1,039
Utica Shale (2)	1,109	5,216	3,904
Total	$163,192	$158,259	$91,576
NGLs			
Wattenberg Field	$132,820	$104,298	$52,919
Delaware Basin	55,148	20,756	645
Utica Shale (2)	840	4,718	3,358
Total	$188,808	$129,772	$56,922

Revenue by Operating Region			
Wattenberg Field	$1,046,051	$765,652	$468,720
Delaware Basin	339,265	124,684	5,602
Utica Shale (2)	4,645	22,748	23,031
Total	$1,389,961	$913,084	$497,353

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(1) As we have elected the modified retrospective method of adoption for the New Revenue Standard, revenues for 2017 and 2016 have not been restated. Such changes would not have been material.

(2) In March 2018, we completed the disposition of our Utica Shale properties.

Contract Assets. Contract assets include material contributions in aid of construction, which are common in purchase and processing agreements with midstream service providers that are our customers. Generally, the intent of the payments is to reimburse the customer for actual costs incurred related to the construction of its gathering and processing infrastructure. Contract assets are classified as long-term assets and included in other assets on our consolidated balance sheet. The contract assets will be amortized as a reduction to crude oil, natural gas and NGLs sales revenue during the periods in which the related production is transferred to the customer.

The following table presents the changes in carrying amounts of the contract assets associated with our crude oil, natural gas and NGLs sales revenue for year ended December 31, 2018:

	Amount (in thousands)
Beginning balance, January 1, 2018	$ 3,746
Additions	2,884
Amortized as a reduction to crude oil, natural gas and NGLs sales	(3,096)
Ending balance, December 31, 2018	$ 3,534

Customer Accounts Receivable. Our accounts receivable include amounts billed and currently due from sales of our crude oil, natural gas and NGLs production. Our gross accounts receivable balance from crude oil, natural gas and NGLs sales at December 31, 2018 and 2017 was $155.8 million and $154.3 million, respectively. We did not record an allowance for doubtful accounts for these receivables at December 31, 2018 or 2017.

NOTE 5 - FAIR VALUE OF FINANCIAL INSTRUMENTS

Determination of Fair Value

Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity.

Derivative Financial Instruments

We measure the fair value of our commodity derivative instruments based on a pricing model that utilizes market-based inputs, including, but not limited to, the contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates such as the LIBOR curve for a similar duration of each outstanding position, volatility factors and nonperformance risk. Nonperformance risk considers the effect of our credit standing on the fair value of derivative liabilities and the effect of our counterparties' credit standings on the fair value of derivative assets. Both inputs to the model are based on published credit default swap rates and the duration of each outstanding derivative position.

We validate our fair value measurement through the review of counterparty statements and other supporting documentation, the determination that the source of the inputs is valid, the corroboration of the original source of inputs through access to multiple quotes, if available, or other information and monitoring changes in valuation methods and assumptions.

Our crude oil and natural gas fixed-price swaps are included in Level 2. Our collars and propane fixed-price swaps are included in Level 3. Our basis swaps are included in Level 2 and Level 3. The following table presents, for each applicable level within the fair value hierarchy, our derivative assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis:

	As of December 31,					
	2018			2017		
	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)					
Total assets	$118,521	$ 59,693	$178,214	$12,949	$ 1,389	$14,338
Total liabilities	(3,364)	(1,364)	(4,728)	(90,569)	(11,076)	(101,645)
Net asset (liability)	$115,157	$ 58,329	$173,486	$(77,620)	$ (9,687)	$(87,307)

The following table presents a reconciliation of our Level 3 commodity derivative instruments measured at fair value:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Fair value of Level 3 instruments, net asset (liability) beginning of period	$(9,687)	$(9,574)	$91,288
Changes in fair value included in consolidated statements of operations line item:			
Commodity price risk management gain (loss), net	63,257	6,241	(28,550)
Settlements included in consolidated statements of operations line items:			
Commodity price risk management (loss), net	4,759	(6,354)	(72,312)
Fair value of Level 3 instruments, net asset (liability) end of period	$58,329	$(9,687)	$(9,574)
Net change in fair value of Level 3 unsettled derivatives included in consolidated statements of operations line item:			
Commodity price risk management gain (loss), net	$—	$(866)	$(12,905)
Total	$—	$(866)	$(12,905)

The significant unobservable input used in the fair value measurement of our derivative contracts is the implied volatility curve, which is provided by a third-party vendor. A significant increase or decrease in the implied volatility, in isolation, would have a directionally similar effect resulting in a significantly higher or lower fair value measurement of our Level 3 derivative contracts. There has been no change in the methodology we apply to measure the fair value of our Level 3 derivative contracts during the periods covered by the financial statements.

Non-Derivative Financial Assets and Liabilities

The carrying value of the financial instruments included in current assets and current liabilities approximate fair value due to the short-term maturities of these instruments.

We utilize fair value on a nonrecurring basis to review our crude oil and natural gas properties and goodwill for possible impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such assets. The fair value of the properties is determined based upon estimated future discounted cash flow, a Level 3 input, using estimated production and prices at which we reasonably expect the crude oil and natural gas will be sold. The fair value of the goodwill is determined using either a qualitative method or a quantitative method, both of which utilize market data, a Level 3 input, in the derivation of the value estimation.

The portion of our long-term debt related to our revolving credit facility approximates fair value due to the variable nature of related interest rates. We have not elected to account for the portion of our debt related to our senior notes under the fair value option; however, we have determined an estimate of the fair values based on measurements of trading activity and broker and/or dealer quotes, respectively, which are published market prices, and therefore are Level 2 inputs. The table below presents these estimates of the fair value of the portion of our long-term debt related to our senior notes and convertible notes as of December 31, 2018 and 2017:

	As of December 31,			
	2018		2017	
	Estimated Fair Value	Percent of Par	Estimated Fair Value	Percent of Par
	(in millions)			
Senior notes:				
2021 Convertible Notes	$175.4	87.7 %	$195.6	97.8 %
2024 Senior Notes	370.2	92.5 %	416.0	104.0 %
2026 Senior Notes	532.4	88.7 %	616.5	102.8 %

The carrying value of our capital lease obligations approximates fair value due to the variable nature of the imputed interest rates and the duration of the related vehicle lease.

NOTE 6 - COMMODITY DERIVATIVE FINANCIAL INSTRUMENTS

Our results of operations and operating cash flows are affected by changes in market prices for crude oil, natural gas and NGLs. To manage a portion of our exposure to price volatility from producing crude oil, natural gas and propane, which is an element of our NGLs, we enter into commodity derivative contracts to protect against price declines in future periods. While we structure these commodity derivatives to reduce our exposure to decreases in commodity prices, they also limit the benefit we might otherwise receive from price increases.

We believe our commodity derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. As of December 31, 2018, we had commodity derivatives positions covering approximately 11.0 MMBbls and 8.6 MMBbls of crude oil production for 2019 and 2020, respectively. As of the same date, we had hedged approximately 26.4 Bcf of natural gas for 2019. Our commodity derivative contracts have been entered into at no cost to us as we hedge our anticipated production at the then-prevailing commodity market prices, without adjustment for premium or discount.

As of December 31, 2018, our derivative instruments were comprised of collars, fixed-price commodity swaps and basis protection swaps.

- Collars contain a fixed floor price (put) and ceiling price (call). If the index price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and index price from the counterparty. If the index price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and index price to the counterparty. If the index price is between the put and call strike price, no payments are due to or from the counterparty;
- Fixed-price commodity swaps are arrangements that guarantee a fixed price. If the index price is below the fixed contract price, we receive the market price from the purchaser and receive the difference between the index price and the fixed contract price from the counterparty. If the index price is above the fixed contract price, we receive the market price from the purchaser and pay the difference between the index price and the fixed contract price to the counterparty. If the index price and contract price are the same, no payment is due to or from the counterparty;

- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For basis protection swaps, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract. If the market price and contract price are the same, no payment is due to or from the counterparty.

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

As of December 31, 2018, we had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

Commodity/ Index/ Maturity Period	Collars Quantity (Crude oil - MBls Natural Gas - BBtu)	Collars Weighted-Average Contract Price Floors	Collars Weighted-Average Contract Price Ceilings	Fixed-Price Swaps Quantity (Crude Oil - MBbls Gas and Basis-BBtu)	Fixed-Price Swaps Weighted-Average Contract Price	Fair Value December 31, 2018 (1) (in thousands)
Crude Oil						
NYMEX						
2019	2,600	$ 56.54	$ 68.13	8,400	$ 53.86	$ 82,305
2020	3,600	55.00	71.68	5,000	62.07	92,359
Total Crude Oil	6,200			13,400		$ 174,664
Natural Gas						
NYMEX						
2019	—	—	—	26,008	2.91	1,408
Dominion South						
2019	—	—	—	372	3.13	30
Columbia						
2019	—	—	—	3	2.40	—
Total Natural Gas	—			26,383		$ 1,438
Basis Protection - Natural Gas						
CIG						
2019	—	—	—	25,924	(0.78)	(2,616)
Total Basis Protection - Natural Gas	—			25,924		$ (2,616)
Commodity Derivatives Fair Value						$ 173,486

(1) Approximately 33.5 percent of the fair value of our commodity derivative assets and 28.9 percent of the fair value of our commodity derivative liabilities were measured using significant unobservable inputs (Level 3).

The following table presents the balance sheet location and fair value amounts of our commodity derivative instruments on the consolidated balance sheets as of December 31, 2018 and 2017:

Derivative instruments:		Consolidated balance sheet line item	2018	2017
			(in thousands)	
Derivative assets:	Current			
	Commodity derivative contracts	Fair value of derivatives	$ 84,492	$ 7,340
	Basis protection derivative contracts	Fair value of derivatives	—	6,998
			84,492	14,338

	Non-current			
	Commodity derivative contracts	Fair value of derivatives	93,722	—
			93,722	—
Total derivative assets			$178,214	$14,338
Derivative liabilities:	Current			
	Commodity derivative contracts	Fair value of derivatives	$748	77,999
	Basis protection derivative contracts	Fair value of derivatives	2,616	234
	Rollfactor derivative contracts	Fair value of derivatives	—	1,069
			3,364	79,302
	Non-current			
	Commodity derivative contracts	Fair value of derivatives	1,364	22,343
Total derivative liabilities			$4,728	$101,645

The following table presents the impact of our derivative instruments on our consolidated statements of operations:

Consolidated statements of operations line item	Year Ended December 31, 2018	2017	2016
	(in thousands)		
Commodity price risk management gain (loss), net			
Net settlements	$(115,538)	$13,324	$208,103
Net change in fair value of unsettled derivatives	260,775	(17,260)	(333,784)
Total commodity price risk management gain (loss), net	$145,237	$(3,936)	$(125,681)

All of our financial derivative agreements contain master netting provisions that provide for the net settlement of all contracts through a single payment in the event of early termination. We have elected not to offset the fair value positions recorded on our consolidated balance sheets.

The following table reflects the impact of netting agreements on gross derivative assets and liabilities:

As of December 31, 2018	Derivative instruments, gross	Effect of master netting agreements	Derivative instruments, net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$178,214	$ (3,985)	$ 174,229
Liability derivatives:			
Derivative instruments, at fair value	$4,728	$ (3,985)	$ 743

As of December 31, 2017	Derivative instruments, gross	Effect of master netting agreements	Derivative instruments, net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$14,338	$(14,173)	$ 165
Liability derivatives:			
Derivative instruments, at fair value	$101,645	$(14,173)	$ 87,472

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 7 - CONCENTRATION OF RISK

Accounts Receivable. The following table presents the components of accounts receivable, net of allowance for doubtful accounts:

	As of December 31,	
	2018	2017
	(in thousands)	
Crude oil, natural gas and NGLs sales	$155,756	$154,260
Joint interest billings	19,580	34,576
Derivative counterparties	3,937	(18)
Income tax receivable	—	6,015
Other	6,542	5,893
Allowance for doubtful accounts	(4,381)	(3,128)
Accounts receivable, net	$181,434	$197,598

Our accounts receivable primarily relate to sales of our crude oil, natural gas and NGLs production, receivable balances from other third parties that own working interests in the properties we operate, and derivative counterparties. For the years ended December 31, 2018 and 2017, amounts written off to allowance for doubtful accounts were not material. As of December 31, 2018, two of our customers represent 10 percent or greater of our accounts receivable balance. As of December 31, 2017, none of our customers represented 10 percent or greater of our accounts receivable balance.

Major Customers. The following table presents the individual customers constituting 10 percent or more of total revenues:

	Year Ended December 31,		
Customer	2018	2017	2016
DCP Midstream, LP	12.5%	19.6%	20.2%
Suncor Energy Marketing, Inc.	— %	16.4%	22.3%
Aka Energy Group, LLC	— %	— %	13.4%
Concord Energy, LLC	— %	— %	13.4%
Bridger Energy, LLC	— %	— %	11.5%

Derivative Counterparties. A portion of our liquidity relates to commodity derivative instruments that enable us to manage a portion of our exposure to price volatility from producing crude oil, natural gas and NGLs. These arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use financial institutions who are also major lenders under our revolving credit facility as counterparties to our commodity derivative contracts. To date, we have had no derivative counterparty default losses. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the potential impact of nonperformance of our current counterparties on the fair value of our derivative instruments is not significant at December 31, 2018.

Note Receivable. Note Receivable. In 2014, we sold our entire 50 percent ownership interest in PDC Mountaineer, LLC to an unrelated third-party. As part of the consideration, we received a promissory note (the “Promissory Note”) for a principal sum of $39.0 million. We regularly analyzed the Promissory Note for evidence of collectibility, evaluating factors such as the creditworthiness of the issuer of the Promissory Note and the value of the issuer's assets. Based upon this analysis, during the quarter ended March 31, 2016, we recognized a provision and recorded an allowance for uncollectible notes receivable for the $44.0 million accumulated outstanding balance, including interest. In April 2017, we sold the Promissory Note to an unrelated third-party buyer for approximately $40.2 million in cash. Accordingly, we reversed $40.2 million of the provision for uncollectible notes receivable during the second quarter of 2017.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Other Accrued Expenses. The following table presents the components of other accrued expenses:

	As of December 31,	
	2018	2017
	(in thousands)	
Employee benefits	$25,811	$22,383
Asset retirement obligations	25,598	15,801
Environmental expenses	3,038	1,374
Other	20,686	3,429
Other accrued expenses	$75,133	$42,987

Other Liabilities. The following table presents the components of other liabilities as of:

	As of December 31,	
	2018	2017
	(in thousands)	
Production taxes	$61,310	$50,476
Deferred oil gathering credit	22,710	—
Other	8,644	6,857
Other liabilities	$92,664	$57,333

Deferred Oil Gathering Credit. In January 2018, we received a payment of $24.1 million from a midstream service provider for the execution of an amendment to an existing crude oil purchase and sale agreement signed in December 2017. The amendment was effective contingent upon certain events which occurred in late January 2018. The amendment, among other things, dedicates crude oil from the majority of our Wattenberg Field acreage to the midstream provider's gathering lines and extends the term of the agreement through December 2029. The payment will be amortized using the straight-line method over the life of the amendment. Amortization charges totaling approximately $1.4 million for 2018 related to the deferred oil gathering credit are included as a reduction to transportation, gathering and processing expenses in our consolidated statements of operations.

NOTE 8 - PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net of accumulated DD&A:

	As of December 31,	
	2018	2017
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$5,452,613	$4,356,922
Unproved	492,594	1,097,317
Total crude oil and natural gas properties	5,945,207	5,454,239

Infrastructure and other	60,612	109,359
Land and buildings	11,243	10,960
Construction in progress	356,095	196,024
Properties and equipment, at cost	6,373,157	5,770,582
Accumulated DD&A	(2,370,295)	(1,837,115)
Properties and equipment, net	$4,002,862	$3,933,467

Acreage Exchanges. In November 2018, we completed a nonmonetary acreage exchange that resulted in our acquisition of approximately 12,300 net acres that consolidated our position in the core area of the Wattenberg Field. We recognized a gain of approximately $6.0 million related to the exchange based on the fair value of the assets surrendered.

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Also during 2018, we completed another nonmonetary acreage exchange in the Wattenberg Field, resulting in us acquiring approximately 2,500 net acres and $3.7 million in cash. It was concluded that this transaction lacked commercial substance, and accordingly, the trade was recorded at the previous historical cost of the assets exchanged, less cash received.

In 2017, we completed two significant acreage exchanges that consolidated certain acreage positions in the core area of the Wattenberg Field. Pursuant to the transactions, we exchanged leasehold acreage with a limited number of wells that were in the process of being drilled and completed. Upon closing, we received approximately 15,900 net acres in exchange for approximately 16,200 net acres with minimal cash exchanged between the parties. The differences in net acres are primarily due to variances in working and net revenue interests and in midstream contracts. The assets exchanged were all in the same unit-of-production for property considerations, so it was concluded that this transaction was outside of the scope of the accounting requirements for recording the transaction at fair value and determining gain or loss on the non-monetary exchanges. The new acreage and underlying property costs were recorded at the previous historical cost of the assets we exchanged.

Classification of Assets and Liabilities as Held-for-Sale. During the fourth quarter of 2018, as part of our plan to divest certain of our Delaware Basin crude oil gathering, natural gas gathering and produced water gathering and disposal assets, we began actively marketing the assets for sale; therefore, these assets are classified as held-for-sale as they met the criteria for such classification at December 31, 2018. We currently expect to execute agreements on the sales of these assets in the first half of 2019. Our Delaware Basin crude oil gathering, natural gas gathering and produced water gathering and disposal assets do not represent a strategic shift in our operations or have a significant impact on our operations or financial results; therefore, we will not account for it as a discontinued operation. Also included in the assets held-for-sale are certain non-core Delaware Basin crude oil and natural gas properties.

During 2017, as part of our plan to divest the Utica Shale properties, we engaged an investment banking firm and began actively marketing the properties for sale; therefore, these properties were classified as held-for-sale as they met the criteria for such classification at December 31, 2017. In March 2018, we completed the Utica Shale Divestiture for net cash proceeds of approximately $39.0 million. We recorded a loss on sale of properties and equipment of $1.4 million for 2018, which included post-closing adjustments. The Utica Shale Divestiture did not represent a strategic shift in our operations or have a significant impact on our operations or financial results; therefore, we did not account for it as a discontinued operation.

The following table presents balance sheet data related to assets and liabilities held-for-sale:

	As of December 31,	
	2018	2017
	(in thousands)	
Assets		
Properties and equipment, net	$137,448	$40,583
Other assets	3,257	—
Total assets	$140,705	$40,583
Liabilities		
Asset retirement obligation	$4,111	$499
Total liabilities	$4,111	$499

Impairment of Properties and Equipment

The following table presents impairment charges recorded for properties and equipment:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Impairment of proved and unproved properties	$458,397	$285,465	$5,562
Amortization of individually insignificant unproved properties	—	422	1,379
Land and buildings	—	—	3,032
Total impairment of properties and equipment	$458,397	$285,887	$9,973

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

During 2018, we recorded impairment charges totaling $458.4 million as we identified current and anticipated near-term leasehold expirations within our non-focus areas of the Delaware Basin and made the determination that we would no longer pursue plans to develop these properties. The impaired non-focus leasehold typically has a higher gas to oil ratio and a greater degree of geologic complexity than our other Delaware Basin properties and is further impacted by widening crude oil and natural gas differentials and increased well development costs. We continue to explore options for our non-focus areas and monitor them for possible future impairment based on similar analyses. We determined the fair value of the properties based upon estimated future discounted cash flow, a Level 3 input, using estimated production and prices at which we reasonably expect the crude oil and natural gas will be sold.

The impairment charges noted above include the correction of two errors in the timing of the reporting of certain impairments. In 2018, we corrected an error in our calculation of unproved properties and goodwill originally recorded in 2017, resulting in an additional impairment charge of $6.3 million being recorded during the three months ended March 31, 2018. Further, during the fourth quarter of 2018, we corrected for an additional $8.4 million impairment of unproved properties relating to the three months ended September 30, 2018. This correction had no impact on the year ended December 31, 2018. We evaluated these errors under the guidance of Accounting Standards Codification 250, Accounting Changes and Error Corrections ("ASC 250"). Based on the guidance in ASC 250, we determined that the errors did not have a material impact on our previously-issued financial statements or those of the period of correction.

During 2017, we recorded a charge related to two exploratory dry holes we had drilled in the western area of our Culberson County acreage in the Delaware Basin. We then assessed the impact of the dry holes and various factors related thereto, including the operational and geologic data obtained, the current increased cost environment for drilling and completion services in the Delaware Basin, our decreased future commodity price outlook and the terms of the related lease agreements. Based on the results of this assessment, we concluded that the underlying geologic risk and the challenged economics of future capital expenditures reduced the likelihood that we would perform future development in this area over the remaining lease term for this acreage. Accordingly, we recorded an impairment of $251.6 million covering approximately 13,400 acres during 2017. The amount of the impairment was based on the value assigned to individual lease acres in the final purchase price allocation of the Delaware Basin acquisition. This allocation had included the consideration paid to the sellers, including the effect of the non-cash impact from the deferred tax liability created at the time of the acquisition. We recorded approximately $29 million of additional lease impairments in the Delaware Basin and an impairment charge of $2.1 million related to the Utica Shale properties that were classified as held-for-sale during 2017. Due to the aforementioned events and circumstances, we also evaluated our proved property for possible impairment and concluded that no further impairments were necessary. Future deterioration of commodity prices or other operating circumstances could result in additional impairment charges to our properties and equipment.

Suspended Well Costs. The following table presents the capitalized exploratory well cost pending determination of proved reserves and included in properties and equipment, net on the consolidated balance sheets:

	As of December 31,	
	2018	2017
	(in thousands, except for number of wells)	

Beginning balance	$15,448	$—
Additions to capitalized exploratory well costs pending the determination of proved reserves	35,127	51,776
Reclassifications to proved properties	(38,387)	(36,328)
Balance at December 31,	$12,188	$15,448
Number of wells pending determination	2	3

90

Exploration Expenses. The following table presents the major components of exploration, geologic and geophysical expense:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Exploratory dry hole costs	$113	$41,297	$—
Geological and geophysical costs, including seismic purchases	3,401	3,881	3,472
Operating, personnel and other	2,690	2,156	1,197
Total exploration, geologic and geophysical expense	$6,204	$47,334	$4,669

Exploratory dry hole costs. During 2017, two exploratory dry holes, associated lease costs and related infrastructure assets in the Delaware Basin were expensed at a cost of $41.3 million. The conclusion to expense these items was based on our determination that the acreage on which these wells were drilled was exploratory in nature and, following drilling, that the hydrocarbon production was insufficient for the wells to be deemed economically viable.

NOTE 9 - GOODWILL

Goodwill that resulted from the purchase price allocation of a business combination in the Delaware Basin in December 2016 was determined to be $75.1 million. In 2017, we evaluated goodwill for impairment by performing a quantitative test, which involves comparing the estimated fair value of the goodwill reporting unit, which we define as the Delaware Basin, to the carrying value. We determined the fair value of the goodwill by using an estimated after-tax future discounted cash flow analysis, along with a combination of market-based pricing factors for similar acreage, reserve valuation techniques and other fair value considerations. The discounted cash flow analysis used to estimate fair value was based on known or knowable information at the interim measurement date. Fair value determinations require considerable judgment and are sensitive to changes in underlying assumptions and factors. The quantitative test resulted in a determination that a full impairment charge of $75.1 million was required; therefore, the charge was recorded in 2017.

NOTE 10 - LONG-TERM DEBT

Long-term debt consists of the following:

	As of December 31,	
	2018	2017
	(in thousands)	
Senior notes:		
1.125% Convertible Notes due 2021:		
Principal amount	$200,000	$200,000
Unamortized discount	(22,766)	(30,328)
Unamortized debt issuance costs	(2,640)	(3,615)
1.125% Convertible Notes due 2021, net of unamortized discount and debt issuance costs	174,594	166,057
6.125% Senior Notes due 2024:		
Principal amount	400,000	400,000
Unamortized debt issuance costs	(5,590)	(6,570)
6.125% Senior Notes due 2024, net of unamortized debt issuance costs	394,410	393,430
5.75% Senior Notes due 2026:		
Principal amount	600,000	600,000
Unamortized debt issuance costs	(6,628)	(7,555)
5.75% Senior Notes due 2026, net of unamortized debt issuance costs	593,372	592,445
Total senior notes	1,162,376	1,151,932
Revolving credit facility	32,500	—
Total long-term debt, net of unamortized discount and debt issuance costs	1,194,876	1,151,932
Less current portion of long-term debt	—	—
Long-term debt	$1,194,876	$1,151,932

Senior Notes

2021 Convertible Notes. In September 2016, we issued $200.0 million of 1.125% convertible senior notes due 2021 in a public offering. The 2021 Convertible Notes are governed by an indenture dated September 14, 2016. The maturity for the payment of principal is September 15, 2021. Interest at the rate of 1.125% per year is payable in cash semiannually in arrears on each March 15 and September 15. The proceeds from the issuance of the 2021 Convertible Notes, after deducting offering expenses and underwriting discounts, were used to fund a portion of the purchase price of acquisitions in the Delaware Basin, to pay related fees and expenses and for general corporate purposes.

The 2021 Convertible Notes are convertible prior to March 15, 2021 only upon specified events and during specified periods and, thereafter, at any time, in each case at an initial conversion rate of 11.7113 shares of our common stock per $1,000 principal amount of the 2021 Convertible Notes, which is equal to an initial conversion price of approximately $85.39 per share. The conversion rate is subject to adjustment upon certain events. Upon conversion, the 2021 Convertible Notes may be settled, at our sole election, in shares of our common stock, cash or a combination thereof. We have initially elected a combination settlement method to satisfy our conversion obligation, which allows us to settle the principal amount of the 2021 Convertible Notes in cash and to settle the excess conversion value, if any, in shares, as well as cash in lieu of fractional shares.

We may not redeem the 2021 Convertible Notes prior to their maturity date. If we undergo a "fundamental change", as defined in the indenture for the 2021 Convertible Notes, subject to certain conditions, holders of the 2021 Convertible Notes may require us to repurchase all or part of the 2021 Convertible Notes for cash at a price equal to 100 percent of the principal amount of the 2021 Convertible Notes to be repurchased, plus any accrued and unpaid interest to, but excluding, the fundamental change repurchase date. The occurrence of a fundamental change will also result in the 2021 Convertible Notes becoming convertible.

We allocated the gross proceeds of the 2021 Convertible Notes between the liability and equity components of the debt. The initial $160.5 million liability component was determined based on the fair value of similar debt instruments excluding the conversion feature for similar terms and priced on the same day we issued the 2021 Convertible Notes. The initial $39.5 million equity component represents the debt discount and was calculated as the difference between the fair value of the debt and the gross proceeds of the 2021 Convertible Notes. Approximately $4.8 million in costs associated with the issuance of the 2021 Convertible Notes have been capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes using the effective interest method. As of December 31, 2018, the unamortized debt discount will be amortized over the remaining contractual term to maturity of the 2021 Convertible Notes using the effective interest method. Based upon the December 31, 2018 stock price of $29.76 per share, the “if-converted” value of the 2021 Convertible Notes did not exceed the principal amount.

2024 Senior Notes. In September 2016, we issued $400.0 million aggregate principal amount of 6.125% senior notes due September 2024. The proceeds from the issuance of the 2024 Senior Notes, after deducting offering expenses and underwriting discounts, were used to fund a portion of the purchase price of acquisitions in the Delaware Basin, to pay related fees and expenses, and for general corporate purposes.

Interest is payable semi-annually in arrears on March 15 and September 15. Approximately $7.8 million in costs associated with the issuance of the 2024 Senior Notes have been capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes using the effective interest method.

The 2024 Senior Notes are redeemable after September 15, 2019 at fixed redemption prices beginning at 104.594 percent of the principal amount redeemed. At any time prior to September 15, 2019, we may redeem all or part of the 2024 Senior Notes at a make-whole price set forth in the indenture which generally approximates the present value of the redemption price at September 15, 2019 and remaining interest payments on the 2024 Senior Notes at the time of redemption.

At any time prior to September 15, 2019, we may redeem up to 35 percent of the outstanding 2024 Senior Notes with proceeds from certain equity offerings at a redemption price of 106.125 percent of the principal amount of the notes redeemed, plus accrued and unpaid interest, if at least 65 percent of the aggregate principal amount of the 2024 Senior Notes remains outstanding after each such redemption and the redemption occurs within 180 days after the closing of the equity offering.

Upon the occurrence of a "change of control," as defined in the indenture for the 2024 Senior Notes, holders will have the right to require us to repurchase all or a portion of the notes at a price equal to 101 percent of the aggregate principal amount of the notes repurchased, together with any accrued and unpaid interest to the date of purchase. In connection with certain asset sales, we may, under certain circumstances, be required to use the net cash proceeds of such asset sale to make an offer to purchase the notes at 100 percent of the principal amount, together with any accrued and unpaid interest to the date of purchase.

2026 Senior Notes. In November 2017, we issued $600.0 million aggregate principal amount 5.75% senior notes due May 15, 2026. The 2026 Senior Notes are governed by an indenture dated November 29, 2017. The maturity for the payment of principal is May 15, 2026. Interest at the rate of 5.75% per year is payable in cash semiannually in arrears on each May 15 and November 15. Approximately $7.6 million in costs associated with the issuance of the 2026 Senior Notes have been capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes using the effective interest method.

The 2026 Senior Notes are redeemable after May 15, 2021 at fixed redemption prices beginning at 104.313 percent of the principal amount redeemed. At any time prior to May 15, 2021, we may redeem all or part of the 2026 Senior Notes at a make-whole price set forth in the indenture which generally approximates the present value of the redemption price at May 15, 2021 and remaining interest payments on the 2026 Senior Notes at the time of redemption.

At any time prior to May 15, 2021 we may redeem up to 35 percent of the outstanding 2026 Senior Notes with proceeds from certain equity offerings at a redemption price of 105.75 percent of the principal amount of the notes redeemed, plus accrued and unpaid interest, if at least 65 percent of the aggregate principal amount of the 2026 Senior Notes remains outstanding after each such redemption and the redemption occurs within 180 days after the closing of the equity offering.

Upon the occurrence of a "change of control," as defined in the indenture for the 2026 Senior Notes, holders will have the right to require us to repurchase all or a portion of the notes at a price equal to 101 percent of the aggregate principal amount of the notes repurchased, together with any accrued and unpaid interest to the date of purchase. In connection with certain asset sales, we may, under certain circumstances, be required to use the net cash proceeds of such asset sale to make an offer to purchase the notes at 100 percent of the principal amount, together with any accrued and unpaid interest to the date of purchase.

The 2021 Convertible Notes, the 2024 Senior Notes and the 2026 Senior notes are senior unsecured obligations and rank senior in right of payment to our future indebtedness that is expressly subordinated to the notes; equal in right of payment to our existing and future indebtedness that is not so subordinated; effectively junior in right of payment to all of our secured indebtedness to the extent of the value of the assets securing such indebtedness; and structurally junior to all existing and future indebtedness (including trade payables) incurred by our non-guarantor subsidiaries. Our wholly-owned subsidiary, PDC Permian, Inc., is a guarantor of our obligations under the 2021 Convertible Notes, the 2024 Senior Notes and the 2026 Senior Notes.

The indentures governing the 2024 Senior Notes and 2026 Senior Notes contain covenants that, among other things, limit our ability and the ability of our subsidiaries to incur additional indebtedness; pay dividends or make distributions on our stock; purchase or redeem stock or subordinated indebtedness; make investments; create certain liens; enter into agreements that restrict distributions or other payments by restricted subsidiaries to us; enter into transactions with affiliates; sell assets; consolidate or merge with or into other companies or transfer all or substantially of our assets; and create unrestricted subsidiaries.

As of December 31, 2018, we were in compliance with all covenants related to the 2021 Convertible Notes, 2024 Convertible Notes and the 2026 Senior Notes.

Revolving Credit Facility

In May 2018, we entered into a Fourth Amended and Restated Credit Agreement (the “Restated Credit Agreement”). The Restated Credit Agreement amends and restates our Third Amended and Restated Credit Agreement dated as of May 21, 2013, as amended. Among other things, the Restated Credit Agreement provides for a maximum credit amount of $2.5 billion, an initial borrowing base of $1.3 billion and an initial elected commitment amount of $700 million. The amount we may borrow under the Restated Credit Agreement is subject to certain limitations under our Notes. In addition, the Restated Credit Agreement extends the maturity date of the facility to May 2023, reflects improved covenant flexibility and certain reductions in interest rates applicable to borrowings under the facility and includes a $25 million swingline facility. In October 2018, we increased the commitment level on our revolving credit facility to the current borrowing base amount of $1.3 billion.

The revolving credit facility is available for working capital requirements, capital investments, acquisitions, to support letters of credit and for general corporate purposes. The borrowing base is based on, among other things, the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests. The borrowing base is subject to a semi-annual redetermination on November 1 and May 1 based upon quantification of our reserves at June 30 and December 31, and is also subject to a redetermination upon the occurrence of certain events.

The outstanding principal amount under the revolving credit facility accrues interest at a varying interest rate that fluctuates with an alternate base rate (equal to the greatest of the administrative agent's prime rate, the federal funds rate plus a premium and the rate for dollar deposits in the London interbank market (“LIBOR”) for one month plus a premium) or, at our election, a rate equal to LIBOR for certain time periods. Additionally, commitment fees, interest margin and other bank fees, charged as a component of interest, vary with our utilization of the facility. As of December 31, 2018, the applicable interest margin is 0.25 percent for the alternate base rate option or 1.25 percent for the LIBOR option, and the unused commitment fee is 0.375 percent. Principal payments are generally not required until the revolving credit facility expires in May 2023, unless the borrowing base falls below the outstanding balance.

The revolving credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests on a quarterly basis. The financial tests, as defined per the revolving credit facility, include requirements to: (a) maintain a minimum current ratio of 1.0:1.0 and (b) not exceed a maximum leverage ratio of 4.0:1.0. As of December 31, 2018, we were in compliance with all the revolving credit facility covenants.

As of December 31, 2018 and 2017, debt issuance costs related to our revolving credit facility were $11.5 million and $6.2 million, respectively, and are included in other assets on the consolidated balance sheets. As of December 31, 2018 and 2017, availability under our revolving credit facility was $1.3 billion and $700 million, respectively. As of December 31, 2018, the weighted-average interest rate on the outstanding balance on our revolving credit facility, exclusive of fees on the unused commitment, was 4.5 percent.

NOTE 11 - CAPITAL LEASES

We periodically enter into non-cancelable lease agreements for vehicles utilized by our operations and field personnel. These leases are being accounted for as capital leases, as the present value of minimum monthly lease payments, including the residual value guarantee, exceeds 90 percent of the fair value of the leased vehicles at inception of the lease.

The following table presents leased vehicles under capital leases:

	As of December 31,	
	2018	2017
	(in thousands)	
Vehicles	$7,941	$6,249
Accumulated depreciation	(3,368)	(1,882)
	$4,573	$4,367

Future minimum lease payments by year and in the aggregate, under non-cancelable capital leases with terms of one year or more, consist of the following:

For the Twelve Months Ending December 31,	Amount (in thousands)
2019	$ 2,111
2020	2,236
2021	698
2022	381
2023	134
	5,560
Less executory cost	(278)
Less amount representing interest	(603)
Present value of minimum lease payments	$ 4,679
Short-term capital lease obligations	$ 1,779
Long-term capital lease obligations	2,900
	$ 4,679

Short-term capital lease obligations are included in other accrued expenses on the consolidated balance sheets. Long-term capital lease obligations are included in other liabilities on the consolidated balance sheets.

NOTE 12 - ASSET RETIREMENT OBLIGATIONS

The following table presents the changes in carrying amounts of the asset retirement obligations associated with our crude oil and natural gas properties and midstream assets:

	Year Ended December 31,	
	2018	2017
	(in thousands)	
Beginning balance	$87,306	$92,387
Obligations incurred with development activities	2,793	3,638
Obligations incurred with acquisition	4,332	—
Accretion expense	5,075	6,306
Revisions in estimated cash flows	30,166	(2,860)
Obligations discharged with asset retirements	(14,651)	(12,165)
Balance at December 31	115,021	87,306
Less liabilities held-for-sale	(4,111)	(499)
Less current portion	(25,598)	(15,801)
Long-term portion	$85,312	$71,006

Our estimated asset retirement obligations liability is based on historical experience in plugging and abandoning wells, estimated economic lives and estimated plugging and abandonment costs considering federal and state regulatory requirements in effect. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations liability, a corresponding adjustment is made to the properties and equipment balance. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and as accretion expense. Short-term asset retirement obligations are included in other accrued expenses on the consolidated balance sheets.

The revisions in estimated cash flows during 2018 were primarily due to changes in estimates of costs for materials and services related to the plugging and abandonment of wells and the shortening of the estimated expected lives of wells.

NOTE 13 - COMMITMENTS AND CONTINGENCIES

Firm Transportation and Processing Agreements. We enter into contracts that provide firm transportation and processing on pipeline systems through which we transport or sell crude oil and natural gas. Satisfaction of the volume requirements includes volumes produced by us, purchased from third parties and produced by our affiliated partnerships and other third-party working, royalty and overriding royalty interest owners, whose volumes we market on their behalf. Our consolidated statements of operations reflect our share of these firm transportation and processing costs. These contracts require us to pay these transportation and processing charges whether or not the required volumes are delivered.

The following table presents gross volume information related to our long-term firm transportation, sales and processing agreements for pipeline capacity and water delivery and disposal commitments:

Area	Year Ending December 31, 2019	2020	2021	2022	2022 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Wattenberg Field	23,934	31,110	31,025	31,025	90,897	207,991	April 30, 2026
Delaware Basin	48,147	37,430	21,307	—	—	106,884	December 31, 2021
Gas Marketing	7,117	7,136	7,056	4,495	—	25,804	August 31, 2022
Total	79,198	75,676	59,388	35,520	90,897	340,679	
Crude oil (MBbls)							
Wattenberg Field	9,713	5,918	5,475	5,475	3,180	29,761	April 30, 2023
Delaware Basin	7,359	8,784	8,030	8,030	8,030	40,233	December 31, 2023
Total	17,072	14,702	13,505	13,505	11,210	69,994	
Water (MBbls)							
Wattenberg Field	3,103	6,207	6,207	6,207	12,413	34,137	December 31, 2024
Delaware Basin	3,650	3,660	3,650	3,650	1,770	16,380	June 26, 2023
Total	6,753	9,867	9,857	9,857	14,183	50,517	
Dollar commitment (in thousands)	$106,844	$78,209	$74,409	$67,354	$102,925	$429,741	

Wattenberg Field. In anticipation of our future drilling activities in the Wattenberg Field, we have entered into two facilities expansion agreements with our primary midstream provider to expand and improve its natural gas gathering pipelines and processing facilities. The midstream provider completed and turned on line the first of the two 200 MMcfd cryogenic plants in August 2018. The second plant is currently scheduled to be completed in the second quarter of 2019. We are bound to the volume requirements in these agreements on the first day of the calendar month following the actual in-service date of the relevant plant. Both agreements require baseline volume commitments, consisting of our gross wellhead volume delivered in November 2016 to this midstream provider, and incremental wellhead volume commitments of 51.5 MMcfd and 33.5 MMcfd for the first and second agreements, respectively, for seven years. We may be required to pay shortfall fees for any volumes under the 51.5 MMcfd and 33.5 MMcfd incremental commitments. Any shortfall in these volume commitments may be offset by other producers’ volumes sold to the midstream provider that are greater than a certain total baseline volume. We are also required for the first three years of the contracts to guarantee a certain target profit margin to the midstream provider on these incremental volumes.

Delaware Basin. In May 2018, we entered into a firm sales agreement that is effective from June 2018 through December 2023 with an integrated marketing company for our crude oil production in the Delaware Basin. Contracted volumes are currently 14,600 barrels of crude oil per day and increase over time to 26,400 barrels of crude oil per day. These agreements are expected to provide price diversification through realization of export market pricing via a Corpus Christi terminal and exposure to Brent-weighted prices.

Commodity Sales. For 2018, amounts related to long-term transportation volumes, net to our interest, for Wattenberg Field crude oil and Delaware Basin natural gas were $27.3 million and in accordance with the guidance in the New Revenue Standard, were netted against our crude oil and natural gas sales in our consolidated statements of operations. In addition, for 2018, $1.6 million related to long-term transportation volumes were recorded in transportation, gathering and processing expense in our consolidated statements of operations. For each of 2017 and 2016, amounts related to long-term transportation volumes for Wattenberg Field crude oil and Utica Shale natural gas were $10.0 million and were recorded in transportation, gathering and processing expense in our consolidated statements of operations. In March 2018, we completed the disposition of our Utica Shale properties.

Litigation and Legal Items. We are involved in various legal proceedings. We review the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in our best interests. We have provided the necessary estimated accruals in the accompanying balance sheets where deemed appropriate for litigation and legal related items that are ongoing and not yet concluded. Although the results cannot be known with certainty, we currently believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations or liquidity.

Action Regarding Partnerships. In December 2017, we received an action entitled Dufresne, et al. v. PDC Energy, et al., filed in the United States District Court for the District of Colorado. The complaint states that it is a derivative action brought by a number of limited partner investors seeking to assert claims on behalf of our two affiliated partnerships, Rockies Region 2006 LP and Rockies Region 2007 LP (collectively, the "Partnerships"), against PDC and includes claims for breach of fiduciary duty and breach of contract. The plaintiffs also included claims against two of our senior officers and three independent members of our Board of Directors for alleged breach of fiduciary duty. The lawsuit accuses PDC, as the managing general partner of the Partnerships, of, among other things, failing to maximize the productivity of the Partnerships' crude oil and natural gas wells and improperly assigning the Partnerships only interests in the wells, as opposed to leasehold interests in surrounding acreage. In late April 2018, the plaintiffs filed an amendment to their complaint, which alleges additional facts and purports to add direct class action claims in addition to the original derivative claims. We filed a motion to dismiss this amended complaint and the claims against the individuals named as defendants on July 31, 2018. On February 19, 2019, the court granted the motion to dismiss, in part. It dismissed all claims against the individuals named as defendants. It also held that that the plaintiffs were time-barred from using the failure to assign acreage assignments to support their claims for breach of fiduciary duty against PDC. This action has been stayed as a result of the partnership bankruptcy proceedings described in Partnership Bankruptcy Filings below. We are currently unable to estimate any potential damages resulting from this lawsuit.

Partnership Bankruptcy Filings. On October 30, 2018, the Partnerships filed petitions under Chapter 11 of the Bankruptcy Code (the "Chapter 11 Proceedings") in the United States Bankruptcy Court for the Northern District of Texas, Dallas Division (the "Bankruptcy Court"). The Partnerships intend to enter into a transaction with us, pursuant to which the Partnerships will sell substantially all of their assets to us through a Chapter 11 plan of liquidation (the "Chapter 11 Plan") and provide a release of any claims, including those asserted in Dufresne, et al. v. PDC Energy, et al. (the "Dufresne Case"). The Partnerships remain in possession of their assets and continue to operate their businesses as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court. In addition, a third-party (the "Responsible Party") has been designated for the Partnerships. The Responsible Party is expected to oversee all actions for the Partnerships in connection with the Chapter 11 Proceedings, including actions relating to the anticipated transactions with us and seeking approval of the Chapter 11 Plan. In late November and early December, 2018 the plaintiffs in the Dufresne Case filed several pleadings in the Bankruptcy Court, including one to dismiss the bankruptcy on grounds that PDC had no authority to hire the Responsible Party, the Responsible Party had no authority to cause the Partnerships to file bankruptcy, and the bankruptcy was filed solely for the purpose to gain a litigation advantage in and dismiss the Dufresne Case. The parties have agreed to mediate their disputes with respect to the Dufresne Case and the bankruptcy cases. As a result, on December 17, 2018 the Bankruptcy Court entered an agreed order staying the bankruptcy motions and the Dufresne Case until March 20, 2019 to allow the parties to mediate their disputes. We do not believe that the Partnership's Chapter 11 Proceedings will have a material adverse effect on our financial position, results of operations or liquidity, but we cannot predict the outcome of such proceedings.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to minimize and mitigate the risks from environmental contamination. We conduct periodic reviews and simulated drills to identify changes in our environmental risk profile. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. Except as discussed herein, we are not aware of any material environmental claims existing as of December 31, 2018 which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown potential past non-compliance with environmental laws or other environmental liabilities will not be discovered on our properties. Accrued environmental liabilities are recorded in other accrued expenses on the consolidated balance sheets. The liability ultimately incurred with respect to a matter may exceed the related accrual.

On October 23, 2018, we agreed to an Administrative Order by Consent ("AOC") with the Colorado Oil and Gas Conservation Commission relating to a historical release discovered during the decommissioning of a location in Weld County, Colorado, pursuant to which, among other things, we agreed to a penalty of approximately $130,000, of which 20 percent would be suspended subject to compliance with certain corrective actions identified in the AOC. In addition to the penalty, we agreed to timely complete certain corrective actions set forth in the AOC relating to procedures for completing future work on buried or partially buried produced water vessels, and to reestablish vegetation and otherwise reclaim the location.

Clean Air Act Agreement and Related Consent Decree. In June 2017, following our receipt of a 2015 Clean Air Act information request from the EPA and a 2015 compliance advisory from the Colorado Department of Public Health and Environment's (“CDPHE”) Air Pollution Control Division, the U.S. Department of Justice, on behalf of the EPA and the state of Colorado, filed a complaint against us in the U.S. District Court for the District of Colorado, claiming that we failed to operate and maintain certain condensate collection facilities at 65 facilities so as to minimize leakage of volatile organic compounds in compliance with applicable law.

In October 2017, we entered into a consent decree to resolve the lawsuit and the compliance advisory. Pursuant to the consent decree, we agreed to implement a variety of operational enhancements and mitigation and similar projects, including vapor control system modifications and verification, increased inspection and monitoring and installation of tank pressure monitors. The three primary elements of the consent decree are: (i) fine/supplemental environmental projects ($1.5 million cash fine, plus $1 million in supplemental environmental projects) of which the cash fines and the full cost of supplemental environmental projects were paid in the first and third quarters of 2018, respectively, (ii) injunctive relief with an estimated cost of approximately $18 million, primarily representing capital enhancements to our operations and (iii) mitigation with an estimated cost of $1.7 million. We continue to incur costs associated with these activities. If we fail to comply fully with the requirements of the consent decree with respect to those matters, we could be subject to additional liability. We do not believe that the expenditures resulting from the settlement will have a material adverse effect on our consolidated financial statements.

We are in the process of implementing the consent degree program. Over the course of its execution, we have identified certain immaterial deficiencies in our implementation of the program. We report these immaterial deficiencies to the appropriate authorities and remediate them promptly. We do not believe that the penalties and expenditures associated with the consent decree, including any sanctions associated with these deficiencies, will have a material effect on our financial condition or results of operations, but they may exceed $100,000.

In addition, in December 2018, we were named as a nominal defendant in a derivative action filed in the Delaware chancery court. The complaint, which seeks unspecified monetary damages and various forms of equitable relief, alleges that certain current and former members of our board of directors violated their fiduciary duties, committed waste and were unjustly enriched by, among other things, failing to implement adequate environmental safeguards in connection with the issues that gave rise to the Department of Justice lawsuit and consent decree. We believe that this lawsuit is without merit but cannot predict its outcome.

In addition, we could be the subject of other enforcement actions by regulatory authorities in the future relating to our past, present or future operations.

Lease Agreements. We entered into operating leases, principally for the leasing of natural gas compressors, office space and general office equipment.

The following table presents the minimum future lease payments under the non-cancelable operating leases as of December 31, 2018:

	Year Ending December 31,						
	2019	2020	2021	2022	2023	Thereafter	Total
	(in thousands)						
Minimum Lease Payments	$6,273	$6,365	$6,290	$5,229	$1,385	$ 2,256	$27,798

Operating lease expense for 2018, 2017 and 2016 was $26.7 million, $17.2 million and $10.2 million, respectively.

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 14 - COMMON STOCK

Stock-Based Compensation Plans

2018 Equity Incentive Plan. In May 2018, our stockholders approved a long-term equity compensation plan for our employees and non-employee directors (the “2018 Plan”). The 2018 Plan provides for a reserve of 1,800,000 shares of our common stock that may be issued pursuant to awards under the 2018 Plan and a term that expires in March 2028. As of December 31, 2018, no shares have been issued under the 2018 plan. Shares issued may be either authorized but unissued shares, treasury shares or any combination. Additionally, the 2018 Plan permits the reuse or reissuance of shares of common stock which were canceled, expired, forfeited or paid out in the form of cash. However, shares tendered or withheld to satisfy the exercise price of options or tax withholding obligations, and shares covering the portion of exercised stock-settled stock appreciation rights ("SARs") (regardless of the number of shares actually delivered), count against the share limit. Awards may be issued in the form of options, SARs, restricted stock, restricted stock units ("RSUs"), performance stock units ("PSUs") and other stock-based awards. Awards may vest over periods of continued service or the satisfaction of performance conditions set at the discretion of the Compensation Committee of our Board of Directors (the "Compensation Committee"), with a minimum one-year vesting period applicable to most awards. With regard to SARs and options, awards have a maximum exercisable period of ten years.

2010 Long-Term Equity Compensation Plan. Our Amended and Restated 2010 Long-Term Equity Compensation Plan, which was most recently approved by stockholders in 2013 (as the same has been amended and restated from time to time, the "2010 Plan"), will remain outstanding and we may use the 2010 Plan to grant awards. However, the share reserve of the 2010 Plan is nearly depleted. As of December 31, 2018, there were 284,152 shares available for grant under the 2010 Plan.

The following table provides a summary of the impact of our outstanding stock-based compensation plans on the results of operations for the periods presented:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Stock-based compensation expense	$21,782	$19,353	$19,502
Income tax benefit	(5,210)	(7,372)	(7,296)
Net stock-based compensation expense	$16,572	$11,981	$12,206

Stock Appreciation Rights

The SARs vest ratably over a three-year period and may generally be exercised at any point after vesting through ten years from the date of issuance. Pursuant to the terms of the awards, upon exercise, the executive officers will receive, in shares of common stock, the excess of the market price of the award on the date of exercise over the market price of the award on the date of issuance.

The Compensation Committee awarded SARs to our executive officers in 2017 and 2016. There were no SARs awarded to our executive officers in 2018. The fair value of each SAR award was estimated on the date of grant using a Black-Scholes pricing model using the following assumptions:

	Year Ended December 31,	
	2017	2016
Expected term of award (in years)	6.0 years	6.0 years
Risk-free interest rate	2.0 %	1.8 %
Expected volatility	53.3 %	54.5 %
Weighted-average grant date fair value per share	$38.58	$26.96

The expected term of the award was estimated using historical stock option exercise behavior data. The risk-free interest rate was based on the U.S. Treasury yields approximating the expected life of the award in effect at the time of grant. Expected volatilities were based on our historical volatility. We do not expect to pay or declare dividends in the foreseeable future.

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the changes in our SARs for all periods presented (in thousands, except per share data):

	Year Ended December 31,									
	2018				2017			2016		
	Number of SARs	Weighted-Average Exercise Price	Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value	Number of SARs	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Number of SARs	Weighted-Average Exercise Price	Aggregate Intrinsic Value
Outstanding at January 1,	298,220	$ 47.39	6.5	$ 2,490	244,078	$ 41.36	$ 7,620	326,453	$ 38.99	$ 4,697
Awarded	—	—	—	—	54,142	74.57	—	58,709	51.63	—
Exercised	—	—	—	—	—	—	—	(141,084)	40.16	2,770
Modified	63,969	42.83	—	—	—	—	—	—	—	—
Expired	(71,931)	46.34	—	—	—	—	—	—	—	—
Outstanding at December 31,	290,258	46.64	4.6	125	298,220	47.39	2,490	244,078	41.36	7,620
Exercisable at December 31,	260,101	44.88	4.3	125	223,865	43.28	2,267	174,919	38.72	5,924

We expect all SARs outstanding as of December 31, 2018 to vest. The SARS modified during 2018 were related to one employee and the total compensation cost associated with the modification was not material to our consolidated statement of operations. Total compensation cost related to SARs granted and not yet recognized in our consolidated statements of operations as of December 31, 2018 was $0.5 million. The cost is expected to be recognized over a weighted-average period of 0.5 years.

Restricted Stock Units

Time-Based Awards. The fair value of the time-based RSUs is amortized ratably over the requisite service period, primarily three years. The time-based RSUs generally vest ratably on each anniversary following the grant date that a participant is continuously employed.

The following table presents the changes in non-vested time-based RSUs during 2018:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2017	472,132	$ 60.23
Granted	446,743	50.69
Vested	(249,317)	58.95
Forfeited	(51,151)	56.45
Non-vested at December 31, 2018	618,407	54.16

The following table presents the weighted-average grant date fair value per share and related information as of/for the periods presented:

	As of/Year Ended December 31,		
	2018	2017	2016
	(in thousands, except per share data)		
Total intrinsic value of time-based awards vested	$12,282	$16,303	$18,973
Total intrinsic value of time-based awards non-vested	18,404	24,334	34,812
Market price per common share as of December 31,	29.76	51.54	72.58
Weighted-average grant date fair value per share	50.69	65.14	58.52

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Total compensation cost related to non-vested time-based awards and not yet recognized in our consolidated statements of operations as of December 31, 2018 was $20.7 million. This cost is expected to be recognized over a weighted-average period of 1.8 years.

Performance Stock Units

Market-Based Awards. The fair value of the market-based PSUs is amortized ratably over the requisite service period, primarily three years. The market-based shares vest if the participant is continuously employed throughout the performance period and the market-based performance measure is achieved, with a maximum vesting period of three years. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.
In February 2018, the Compensation Committee awarded a total of 90,778 market-based PSUs to our executive officers. In addition to continuous employment, the vesting of these PSUs is contingent on our total stockholder return ("TSR"), which is essentially our stock price change including any dividends over a three-year period ending on December 31, 2020, as compared to the TSR of a group of peer companies over the same period. The PSUs will result in a payout between 0 percent and 200 percent of the target PSUs awarded. The weighted-average grant date fair value per PSU granted was computed using the Monte Carlo pricing model using the following assumptions:

	Year Ended December 31,		
	2018	2017	2016
Expected term of award (in years)	3 years	3 years	3 years
Risk-free interest rate	2.4 %	1.4 %	1.2 %
Expected volatility	42.3 %	51.4 %	52.3 %

The expected term of the awards was based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the life of the award. The expected volatility was based on our historical volatility.

The following table presents the change in non-vested market-based awards during 2018:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2017	52,349	$ 84.06
Granted	90,778	69.98
Vested	(18,941)	72.54
Forfeited	(21,272)	78.65
Non-vested at December 31, 2018	102,914	74.88

The following table presents the weighted-average grant date fair value per share and related information as of/for the periods presented:

	As of/Year Ended December 31,		
	2018	2017	2016

	(in thousands, except per share data)		
Total intrinsic value of market-based awards vested	$620	$2,687	$6,562
Total intrinsic value of market-based awards non-vested	3,063	2,698	3,514
Market price per common share as of December 31,	29.76	51.54	72.58
Weighted-average grant date fair value per share	69.98	94.02	72.54

Total compensation cost related to non-vested market-based awards not yet recognized in our consolidated statements of operations as of December 31, 2018 was $4.7 million. This cost is expected to be recognized over a weighted-average period of 1.8 years.

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Treasury Share Purchases

In accordance with our stock-based compensation plans, employees may surrender shares of our common stock to settle tax withholding obligations upon the vesting and exercise of share-based awards. Shares acquired that had been issued pursuant to the 2010 Plan are withheld for reissuance for new grants. For shares reissued for new grants under the 2010 Plan, shares are recorded at cost and upon reissuance we reduce the carrying value of shares acquired and held pursuant to the 2010 Plan by the weighted-average cost per share with an offsetting charge to APIC. During the year ended December 31, 2018, we acquired 102,647 shares for payment of tax liabilities and reissued 104,068 shares. As of December 31, 2018, 33,105 shares were available for reissuance pursuant to our 2010 Plan. During the year ended December 31, 2017, we acquired 107,357 shares for payment of tax liabilities and reissued 83,228 shares. As of December 31, 2017, 34,526 shares were available for reissuance pursuant to our 2010 Plan. In addition to the shares available for reissuance as of December 31, 2018 and 2017, we had 12,115 shares and 21,401 shares, respectively, of treasury stock related to a rabbi trust.

Preferred stock

We are authorized to issue 50,000,000 shares of preferred stock, par value $0.01, in one or more series, with such rights, preferences, privileges and restrictions as shall be fixed by our Board of Directors at the time of issuance. As of December 31, 2018, no preferred shares had been issued.

NOTE 15 - INCOME TAXES

The table below presents the components of our provision for income tax (expense) benefit for the years presented:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Current:			
Federal	$886	$8,443	$9,646
State	(188)	(200)	300
Total current income tax benefit	698	8,243	9,946
Deferred:			
Federal	(1,986)	193,809	118,427
State	(4,118)	9,876	18,822
Total deferred income tax (expense) benefit	(6,104)	203,685	137,249
Income tax (expense) benefit	$(5,406)	$211,928	$147,195

The following table presents a reconciliation of the federal statutory rate to the effective tax rate related to our (expense) benefit for income taxes:

	Year Ended December 31,		
	2018	2017	2016
Federal statutory tax rate	21.0 %	35.0 %	35.0 %
State income tax, net	(6.4)	1.8	2.6
Federal tax credits	(52.1)	—	—
Effect of state income tax rate changes	6.7	—	0.6

Change in valuation allowance	45.5	—	—
Non-deductible compensation	21.8	(0.3)	(0.5)
Non-deductible government relations	31.8	—	—
Other non-deductible items	4.9	—	—
Federal tax reform rate reduction	—	33.7	—
Non-deductible goodwill impairment	—	(7.7)	—
Other	(0.4)	(0.1)	(0.3)
Effective tax rate	72.8 %	62.4 %	37.4 %

PDC ENERGY, INC.
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Tax effects of temporary differences that give rise to significant portions of deferred tax assets and deferred tax liabilities at December 31, 2018 and 2017 are presented below. The 2017 amounts include the reduction of our deferred tax assets and liabilities to a projected combined federal and state deferred tax rate of 23.9 percent as a result of the 2017 Tax Act.

	As of December 31,	
	2018	2017
	(in thousands)	
Deferred tax assets:		
Deferred compensation	$9,963	$6,059
Asset retirement obligations	27,166	21,760
Federal NOL carryforward	54,736	19,386
State NOL and tax credit carryforwards, net	13,223	7,815
Federal tax - credit carryforwards	7,756	4,366
Net change in fair value of unsettled derivatives	—	20,929
Prepaid revenue	5,288	—
Other	4,647	2,453
Valuation allowance	(3,380)	—
Total gross deferred tax assets	119,399	82,768
Deferred tax liabilities:		
Properties and equipment	270,565	267,498
Net change in fair value of unsettled derivatives	41,496	—
Convertible debt	5,434	7,262
Total gross deferred tax liabilities	317,495	274,760
Net deferred tax liability	$198,096	$191,992

During the year ending December 31, 2018, we generated a federal net operating loss ("NOL") of $169.1 million and have prior year federal NOL carryforwards of $31.5 million that will begin to expire in 2036. Also, we acquired a federal NOL of $60.1 million as a component of our 2016 acquisition in the Delaware Basin that will begin to expire in 2034 and is subject to an annual limitation of $15.1 million as a result of the acquisition, which constitutes a change of ownership as defined under IRS Code Section 382.

We have a marginal gas well credit of $5.1 million that can be carried forward 20 years and we have alternative minimum tax credits of $2.7 million that may be carried forward, and pursuant to the new tax law will be refunded over the next three years.

As of December 31, 2018, we have state NOL carryforwards of $284.6 million that begin to expire in 2030 and state credit carryforwards of $3.3 million that begin to expire in 2022. Due to the potential non-utilization of our state tax credit carryforwards before their expiration, we have recorded a valuation allowance for the future tax benefit of these credit carryforwards.

Unrecognized tax benefits and related accrued interest and penalties were immaterial for the three-year period ended December 31, 2018. The statutes of limitations for most of our state tax jurisdictions are open for tax year 2014 forward.

The IRS partially accepted our 2017 tax return. The 2017 tax return is in the IRS CAP Program post-filing review process, with no significant tax adjustments currently proposed. We are currently participating in the CAP Program for the review of our 2018 through 2019 tax years. Participation in the CAP Program has enabled us to have minimal uncertain tax benefits associated with our federal tax return filings.

As of December 31, 2018, we were current with our income tax filings in all applicable state jurisdictions.

NOTE 16 - EARNINGS PER SHARE

Basic earnings per share is computed by dividing net earnings by the weighted-average number of common shares outstanding for the period. Diluted earnings per share is similarly computed except that the denominator includes the effect, using the treasury stock method, of unvested restricted stock, outstanding SARs, stock options, convertible notes and shares held pursuant to our non-employee director deferred compensation plan, if including such potential shares of common stock is dilutive.

The following table presents our weighted-average basic and diluted shares outstanding:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Weighted-average common shares outstanding - basic	66,059	65,837	49,052
Dilutive effect of:			
RSUs and PSUs	173	—	—
Other equity-based awards	71	—	—
Weighted-average common shares and equivalents outstanding - diluted	66,303	65,837	49,052

For 2017 and 2016, we reported a net loss. As a result, our basic and diluted weighted-average common shares outstanding were the same because the effect of the common share equivalents was anti-dilutive.

The following table presents the weighted-average common share equivalents excluded from the calculation of diluted earnings per share due to their anti-dilutive effect:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:			
RSUs and PSUs	145	590	689
Convertible notes	—	—	292
Other equity-based awards	109	75	109
Total anti-dilutive common share equivalents	254	665	1,090

In September 2016, we issued the 2021 Convertible Notes, which gave the holders the right to convert the aggregate principal amount into 2.3 million shares of our common stock at a conversion price of $85.39 per share. The 2021 Convertible Notes would be included in the diluted earnings per share calculation using the treasury stock method if the average market share price had exceeded the $85.39 conversion price during the periods presented.

NOTE 17 - SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Supplemental cash flow information:			
Cash payments (receipts) for:			
Interest, net of capitalized interest	$55,586	$69,880	$43,406
Income taxes	(6,719)	(13,925)	167
Non-cash investing activities:			
Issuance of common stock for acquisition of crude oil and natural gas properties	—	—	690,702
Change in accounts payable related to capital expenditures	36,328	50,761	(40,448)
Change in asset retirement obligation, with a corresponding change to crude oil and natural gas properties, net of disposal	37,136	839	4,894
Purchase of properties and equipment under capital leases	1,940	3,497	1,404

NOTE 18 - SUBSIDIARY GUARANTOR

PDC Permian, Inc., our wholly-owned subsidiary, guarantees our obligations under our publicly-registered senior notes. The following presents the consolidating financial information separately for:

(i) PDC Energy, Inc. ("Parent"), the issuer of the guaranteed obligations, including non-material subsidiaries;
(ii) PDC Permian, Inc., the guarantor subsidiary ("Guarantor"), as specified in the indentures related to our senior notes;
(iii) Eliminations representing adjustments to (a) eliminate intercompany transactions between or among Parent, Guarantor and our other subsidiaries and (b) eliminate the investments in our subsidiaries; and
(iv) Parent and subsidiaries on a consolidated basis ("Consolidated").

The Guarantor was 100 percent owned by the Parent beginning in December 2016. The senior notes are fully and unconditionally guaranteed on a joint and several basis by the Guarantor. The guarantee is subject to release in limited circumstances only upon the occurrence of certain customary conditions. Each entity in the consolidating financial information follows the same accounting policies as described in the notes to the consolidated financial statements.

The following consolidating financial statements have been prepared on the same basis of accounting as our consolidated financial statements. Investments in subsidiaries are accounted for under the equity method. Accordingly, the entries necessary to consolidate the Parent and Guarantor are reflected in the eliminations column.

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

	Consolidating Balance Sheets December 31, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$1,398	$—	$—	$1,398
Accounts receivable, net	146,529	34,905	—	181,434
Fair value of derivatives	84,492	—	—	84,492
Prepaid expenses and other current assets	6,725	411	—	7,136
Total current assets	239,144	35,316	—	274,460
Properties and equipment, net	2,270,711	1,732,151	—	4,002,862
Assets held-for-sale	—	140,705	—	140,705
Intercompany receivable	451,601	—	(451,601)	—
Investment in subsidiaries	1,316,945	—	(1,316,945)	—
Fair value of derivatives	93,722	—	—	93,722
Other assets	30,084	2,312	—	32,396
Total Assets	$4,402,207	$1,910,484	$(1,768,546)	$4,544,145
Liabilities and Stockholders' Equity				
Liabilities				
Current liabilities:				
Accounts payable	$110,847	$71,017	$—	$181,864
Production tax liability	53,309	7,410	—	60,719
Fair value of derivatives	3,364	—	—	3,364
Funds held for distribution	90,183	15,601	—	105,784
Accrued interest payable	14,143	7	—	14,150
Other accrued expenses	73,689	1,444	—	75,133
Total current liabilities	345,535	95,479	—	441,014
Intercompany payable	—	451,601	(451,601)	—
Long-term debt	1,194,876	—	—	1,194,876
Deferred income taxes	162,368	35,728	—	198,096
Asset retirement obligations	79,904	5,408	—	85,312
Liabilities held-for-sale	—	4,111	—	4,111
Fair value of derivatives	1,364	—	—	1,364
Other liabilities	91,452	1,212	—	92,664
Total liabilities	1,875,499	593,539	(451,601)	2,017,437
Stockholders' equity				
Common shares	661	—	—	661
Additional paid-in capital	2,519,423	1,766,775	(1,766,775)	2,519,423
Retained earnings	8,727	(449,830)	449,830	8,727
Treasury shares	(2,103)	—	—	(2,103)
Total stockholders' equity	2,526,708	1,316,945	(1,316,945)	2,526,708
Total Liabilities and Stockholders' Equity	$4,402,207	$1,910,484	$(1,768,546)	$4,544,145

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

	Consolidating Balance Sheets December 31, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Assets				
Current assets:				
Cash and cash equivalents	$180,675	$—	$—	$180,675
Accounts receivable, net	160,490	37,108	—	197,598
Fair value of derivatives	14,338	—	—	14,338
Prepaid expenses and other current assets	8,284	329	—	8,613
Total current assets	363,787	37,437	—	401,224
Properties and equipment, net	1,891,314	2,042,153	—	3,933,467
Assets held-for-sale	40,583	—	—	40,583
Intercompany receivable	250,279	—	(250,279)	—
Investment in subsidiaries	1,617,537	—	(1,617,537)	—
Other assets	42,547	2,569	—	45,116
Total Assets	$4,206,047	$2,082,159	$(1,867,816)	$4,420,390
Liabilities and Stockholders' Equity				
Liabilities				
Current liabilities:				
Accounts payable	$85,000	$65,067	$—	$150,067
Production tax liability	35,902	1,752	—	37,654
Fair value of derivatives	79,302	—	—	79,302
Funds held for distribution	83,898	11,913	—	95,811
Accrued interest payable	11,812	3	—	11,815
Other accrued expenses	42,543	444	—	42,987
Total current liabilities	338,457	79,179	—	417,636
Intercompany payable	—	250,279	(250,279)	—
Long-term debt	1,151,932	—	—	1,151,932
Deferred income taxes	62,857	129,135	—	191,992
Asset retirement obligations	65,301	5,705	—	71,006
Liabilities held-for-sale	499	—	—	499
Fair value of derivatives	22,343	—	—	22,343
Other liabilities	57,009	324	—	57,333
Total liabilities	1,698,398	464,622	(250,279)	1,912,741
Stockholders' equity				
Common shares	659	—	—	659
Additional paid-in capital	2,503,294	1,766,775	(1,766,775)	2,503,294
Retained earnings	6,704	(149,238)	149,238	6,704
Treasury shares	(3,008)	—	—	(3,008)
Total stockholders' equity	2,507,649	1,617,537	(1,617,537)	2,507,649
Total Liabilities and Stockholders' Equity	$4,206,047	$2,082,159	$(1,867,816)	$4,420,390

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

	Consolidating Statements of Operations Year Ended December 31, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$1,050,696	$339,265	$ —	$1,389,961
Commodity price risk management gain, net	145,237	—	—	145,237
Other income	10,744	2,717	—	13,461
Total revenues	1,206,677	341,982	—	1,548,659
Costs, expenses and other				
Lease operating expenses	92,228	38,729	—	130,957
Production taxes	67,819	22,538	—	90,357
Transportation, gathering and processing expenses	16,607	20,796	—	37,403
Exploration, geologic and geophysical expense	1,234	4,970	—	6,204
Impairment of properties and equipment	27	458,370	—	458,397
General and administrative expense	152,798	17,706	—	170,504
Depreciation, depletion and amortization	389,841	169,952	—	559,793
Accretion of asset retirement obligations	4,617	458	—	5,075
(Gain) loss on sale of properties and equipment	(4,387)	4,781	—	394
Other expenses	11,829	—	—	11,829
Total costs, expenses and other	732,613	738,300	—	1,470,913
Income (loss) from operations	474,064	(396,318)	—	77,746
Interest expense	(73,251)	2,521	—	(70,730)
Interest income	413	—	—	413
Income (loss) before income taxes	401,226	(393,797)	—	7,429
Income tax (expense) benefit	(98,611)	93,205	—	(5,406)
Equity in loss of subsidiary	(300,592)	—	300,592	—
Net income (loss)	$2,023	$(300,592)	$ 300,592	$2,023

Net loss for the Guarantor for the year ended 2018 is primarily the result of impairment of certain unproved Delaware Basin leasehold positions.

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

	Consolidating Statements of Operations			
	Year Ended December 31, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$788,400	$124,684	$ —	$ 913,084
Commodity price risk management loss, net	(3,936)	—	—	(3,936)
Other income	11,901	567	—	12,468
Total revenues	796,365	125,251	—	921,616
Costs, expenses and other				
Lease operating expenses	68,031	21,610	—	89,641
Production taxes	53,236	7,481	—	60,717
Transportation, gathering and processing expenses	23,301	9,919	—	33,220
Exploration, geologic and geophysical expense	1,092	46,242	—	47,334
Impairment of properties and equipment	4,951	280,936	—	285,887
Impairment of goodwill	—	75,121	—	75,121
General and administrative expense	107,518	12,852	—	120,370
Depreciation, depletion and amortization	403,984	65,100	—	469,084
Accretion of asset retirement obligations	5,965	341	—	6,306
Gain on sale of properties and equipment	(766)	—	—	(766)
Provision for uncollectible notes receivable	(40,203)	—	—	(40,203)
Other expenses	13,157	—	—	13,157
Total costs, expenses and other	640,266	519,602	—	1,159,868
Income (loss) from operations	156,099	(394,351)	—	(238,252)
Loss on extinguishment of debt	(24,747)	—	—	(24,747)
Interest expense	(79,919)	1,225	—	(78,694)
Interest income	2,261	—	—	2,261
Income (loss) before income taxes	53,694	(393,126)	—	(339,432)
Income tax (expense) benefit	(33,643)	245,571	—	211,928
Equity in loss of subsidiary	(147,555)	—	147,555	—
Net loss	$(127,504)	$(147,555)	$ 147,555	$ (127,504)

Net loss for the Guarantor for the year ended 2017 is primarily the result of the exploratory dry hole expense, impairment of certain unproved Delaware Basin leasehold positions and the impairment of goodwill.

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

	Consolidating Statements of Operations Year Ended December 31, 2016			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas, and NGLs sales	$491,750	$5,603	$ —	$497,353
Commodity price risk management loss, net	(125,681)	—	—	(125,681)
Other income	11,241	2	—	11,243
Total revenues	377,310	5,605	—	382,915
Costs, expenses and other				
Lease operating expenses	58,401	1,549	—	59,950
Production taxes	31,132	278	—	31,410
Transportation, gathering and processing expenses	18,263	152	—	18,415
Exploration, geologic and geophysical expense	1,197	3,472	—	4,669
Impairment of properties and equipment	9,973	—	—	9,973
General and administrative expense	112,166	304	—	112,470
Depreciation, depletion and amortization	415,321	1,553	—	416,874
Accretion of asset retirement obligations	7,070	10	—	7,080
Gain on sale of properties and equipment	(43)	—	—	(43)
Provision for uncollectible notes receivable	44,038	—	—	44,038
Other expenses	10,193	—	—	10,193
Total costs, expenses and other	707,711	7,318	—	715,029
Loss from operations	(330,401)	(1,713)	—	(332,114)
Interest expense	(62,002)	30	—	(61,972)
Interest income	963	—	—	963
Loss before income taxes	(391,440)	(1,683)	—	(393,123)
Income tax benefit	147,195	—	—	147,195
Equity in loss of subsidiary	(1,683)	—	1,683	—
Net loss	$(245,928)	$(1,683)	$ 1,683	$(245,928)

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

	Consolidating Statements of Cash Flows Year Ended December 31, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$625,206	$264,096	$ —	$ 889,302
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural gas properties	(482,534)	(463,816)	—	(946,350)
Capital expenditures for other properties and equipment	(9,806)	(1,249)	—	(11,055)
Acquisition of crude oil and natural gas properties	(179,955)	(71)	—	(180,026)
Proceeds from sale of properties and equipment	1,929	1,633	—	3,562
Proceeds from divestiture	44,693	—	—	44,693
Restricted cash	1,249	—	—	1,249
Intercompany transfers	(199,584)	—	199,584	—
Net cash from investing activities	(824,008)	(463,503)	199,584	(1,087,927)
Cash flows from financing activities:				
Proceeds from revolving credit facility	1,072,500	—	—	1,072,500
Repayment of revolving credit facility	(1,040,000)	—	—	(1,040,000)
Payment of debt issuance costs	(7,704)	—	—	(7,704)
Purchase of treasury stock	(5,147)	—	—	(5,147)
Other	(1,373)	(177)	—	(1,550)
Intercompany transfers	—	199,584	(199,584)	—
Net cash from financing activities	18,276	199,407	(199,584)	18,099
Net change in cash and cash equivalents	(180,526)	—	—	(180,526)
Cash and cash equivalents, beginning of period	189,925	—	—	189,925
Cash and cash equivalents, end of period	$9,399	$—	$ —	$ 9,399

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

	Consolidating Statements of Cash Flows Year Ended December 31, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$546,954	$50,859	$ —	$ 597,813
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural gas properties	(439,897)	(297,311)	—	(737,208)
Capital expenditures for other properties and equipment	(3,539)	(1,555)	—	(5,094)
Acquisition of crude oil and natural gas properties	(21,000)	5,372	—	(15,628)
Proceeds from sale of properties and equipment	10,084	(93)	—	9,991
Sale of promissory note	40,203	—	—	40,203
Restricted cash	(9,250)	—	—	(9,250)
Sales of short-term investments	49,890	—	—	49,890
Purchases of short-term investments	(49,890)	—	—	(49,890)
Intercompany transfers	(239,191)	—	239,191	—
Net cash from investing activities	(662,590)	(293,587)	239,191	(716,986)
Cash flows from financing activities:				
Proceeds from issuance of senior notes	592,366	—	—	592,366
Redemption of senior notes	(519,375)	—	—	(519,375)
Payment of debt issuance costs	(50)	—	—	(50)
Purchase of treasury stock	(6,672)	—	—	(6,672)
Other	(1,195)	(76)	—	(1,271)
Intercompany transfers	—	239,191	(239,191)	—
Net cash from financing activities	65,074	239,115	(239,191)	64,998
Net change in cash and cash equivalents	(50,562)	(3,613)	—	(54,175)
Cash and cash equivalents, beginning of period	240,487	3,613	—	244,100
Cash and cash equivalents, end of period	$189,925	$—	$ —	$ 189,925

PDC ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

	Condensed Consolidating Statements of Cash Flows Year Ended December 31, 2016			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$492,893	$(6,630)	$ —	$486,263
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural gas properties	(436,361)	(523)	—	(436,884)
Capital expenditures for other properties and equipment	(2,282)	(1,182)	—	(3,464)
Acquisition of crude oil and natural gas properties	(1,076,256)	2,533	—	(1,073,723)
Proceeds from sale of properties and equipment	4,945	—	—	4,945
Intercompany transfers	(9,415)	—	9,415	—
Net cash from investing activities	(1,519,369)	828	9,415	(1,509,126)
Cash flows from financing activities:				
Proceeds from revolving credit facility	85,000	—	—	85,000
Repayment of revolving credit facility	(122,000)	—	—	(122,000)
Proceeds from issuance of equity, net of issuance costs	855,074	—	—	855,074
Proceeds from issuance of senior notes	392,172	—	—	392,172
Proceeds from issuance of convertible senior notes	193,935	—	—	193,935
Redemption of convertible notes	(115,000)	—	—	(115,000)
Payment of debt issuance costs	(15,556)	—	—	(15,556)
Purchase of treasury shares	(6,935)	—	—	(6,935)
Other	(577)	—	—	(577)
Intercompany transfers	—	9,415	(9,415)	—
Net cash from financing activities	1,266,113	9,415	(9,415)	1,266,113
Net change in cash and cash equivalents	239,637	3,613	—	243,250
Cash and cash equivalents, beginning of period	850	—	—	850
Cash and cash equivalents, end of period	$240,487	$3,613	$ —	$244,100

The condensed consolidating financial statements for the year ended December 31, 2016 represent one month of activity for the Guarantor as the Delaware Basin acquisition closed in December 2016.

PDC ENERGY, INC.
SUPPLEMENTAL INFORMATION
(Unaudited)

SUPPLEMENTAL INFORMATION - UNAUDITED

CRUDE OIL AND NATURAL GAS INFORMATION - UNAUDITED

Net Proved Reserves

All of our crude oil, natural gas and NGLs reserves are located in the U.S. We utilize the services of independent petroleum engineers to estimate our crude oil, natural gas and NGLs reserves. As of December 31, 2018, 2017 and 2016 (as applicable), all of our estimates of proved reserves for the Wattenberg Field and the Utica Shale were based on reserve reports prepared by Ryder Scott Company, L.P., and beginning in 2016 Netherland, Sewell & Associates, Inc. prepared the reserve reports for the Delaware Basin. These reserve estimates have been prepared in compliance with professional standards and the reserves definitions prescribed by the SEC.

Proved reserves are those quantities of crude oil, natural gas and NGLs which can be estimated with reasonable certainty to be economically producible under existing economic conditions and operating methods. Proved developed reserves are the proved reserves that can be produced through existing wells with existing equipment and infrastructure and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for development. All of our proved undeveloped reserves conform to the SEC five-year rule requirement that they be scheduled to be drilled within five years of each location’s initial booking date.

The indicated index prices for our reserves, by commodity, are presented below.

As of December 31,	Average Benchmark Prices (1)		
	Crude Oil (per Bbl) (2)	Natural Gas (per Mcf) (2)	NGLs (per Bbl) (3)
2018	$65.56	$ 3.10	$65.56
2017	51.34	2.98	51.34
2016	42.75	2.48	42.75

The netted back price used to estimate our reserves, by commodity, are presented below.

As of December 31,	Price Used to Estimate Reserves (4)		
	Crude Oil (per Bbl)	Natural Gas (per Mcf)	NGLs (per Bbl)
2018	$61.14	$ 2.15	$23.04
2017	48.68	2.31	20.21
2016	38.67	1.85	11.97

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(1) Per SEC rules, the pricing used to prepare the proved reserves is based on the unweighted arithmetic average of the first of the month prices for the preceding 12 months.

(2) Our benchmark prices for crude oil and natural gas are WTI and Henry Hub, respectively.
(3) For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes.
(4) These prices are based on the index prices and are net of basin differentials, transportation fees, contractual adjustments and Btu adjustments we experienced for the respective commodity.

PDC ENERGY, INC.
SUPPLEMENTAL INFORMATION
(Unaudited)

The following tables present the changes in our estimated quantities of proved reserves:

	Crude Oil, Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved Reserves:				
Proved reserves, January 1, 2016	98,975	660,737	63,727	272,825
Revisions of previous estimates	(22,097)	(80,426)	(7,130)	(42,631)
Extensions, discoveries and other additions	494	4,094	355	1,531
Acquisition of reserves	50,126	305,224	32,586	133,583
Dispositions	(601)	(4,202)	(424)	(1,725)
Production	(8,728)	(51,730)	(4,826)	(22,176)
Proved reserves, December 31, 2016	118,169	833,697	84,288	341,407
Revisions of previous estimates	28,334	96,119	8,104	52,457
Extensions, discoveries and other additions	2,923	11,541	1,158	6,005
Acquisition of reserves	18,971	289,223	19,604	86,778
Dispositions	(653)	(4,597)	(481)	(1,900)
Production	(12,902)	(71,689)	(6,981)	(31,830)
Proved reserves, December 31, 2017	154,842	1,154,294	105,692	452,917
Revisions of previous estimates	26,548	94,738	12,674	55,011
Extensions, discoveries and other additions	8,786	61,750	8,868	27,946
Acquisition of reserves	19,644	148,674	15,936	60,360
Dispositions	(2,507)	(35,750)	(2,656)	(11,121)
Production	(16,964)	(88,017)	(8,527)	(40,160)
Proved reserves, December 31, 2018	190,349	1,335,689	131,987	544,953

Proved Developed Reserves, as of:				
December 31, 2016	30,013	264,452	24,196	98,284
December 31, 2017	46,862	365,332	35,220	142,971
December 31, 2018	61,821	443,151	43,856	179,535
Proved Undeveloped Reserves, as of:				
December 31, 2016	88,156	569,245	60,092	243,122
December 31, 2017	107,980	788,962	70,472	309,946
December 31, 2018	128,528	892,538	88,131	365,418

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	Developed	Undeveloped	Total
	(MBoe)		
Proved reserves, January 1, 2016	70,496	202,329	272,825
Revisions of previous estimates	6,112	(48,743)	(42,631)
Extensions, discoveries and other additions	1,531	—	1,531
Acquisition of reserves	10,229	123,354	133,583
Dispositions	(99)	(1,626)	(1,725)
Production	(22,176)	—	(22,176)
Undeveloped reserves converted to developed	32,192	(32,192)	—
Proved reserves, December 31, 2016	98,285	243,122	341,407
Revisions of previous estimates	18,291	34,166	52,457
Extensions, discoveries and other additions	2,292	3,713	6,005
Acquisition of reserves	1,305	85,473	86,778
Dispositions	(20)	(1,880)	(1,900)
Production	(31,830)	—	(31,830)
Undeveloped reserves converted to developed	54,648	(54,648)	—
Proved reserves, December 31, 2017	142,971	309,946	452,917
Revisions of previous estimates	6,284	48,727	55,011
Extensions, discoveries and other additions	7,874	20,072	27,946
Acquisition of reserves	8,758	51,602	60,360
Dispositions	(4,486)	(6,635)	(11,121)
Production	(40,160)	—	(40,160)
Undeveloped reserves converted to developed	58,294	(58,294)	—
Proved reserves, December 31, 2018	179,535	365,418	544,953

2018 Activity. During 2018, we increased proved reserves by 92.0 MMBoe, or 20 percent, relative to December 31, 2017. The increase in proved reserves was primarily a result of acreage exchange transactions and acquisitions in the Wattenberg Field and reserve additions on proved acreage resulting from our 2018 development activities. In 2018, we produced 40.2 MMboe.

Revisions of Previous Estimates-Proved Developed Reserves. Proved developed reserves experienced a net positive revision of 11.4 MMBoe due to an increase in prices for crude oil, natural gas and NGLs, offset by net negative revisions of 5.1 MMBoe for an increase in operating costs, performance revisions and other items.

Revisions of Previous Estimates-PUDs. Upward revisions to our PUD reserves were related to an increase of 71.7 MMBoe reflecting newly-booked locations on proven acreage resulting from our drilling activities. Partially offsetting this increase was a negative revision of 26.8 MMBoe in the Wattenberg Field due to drilling schedule changes and updated timing for development of certain locations exceeding the five-year rule. Drilling schedule changes, primarily related to 2018 acreage exchanges, resulted in these locations being reclassified from proved to unproved status. All other changes were due to commodity pricing, lease operating expenses and type curve revisions, which resulted in further upward revisions of 3.8 MMBoe of PUD reserves.

Extensions, Discoveries and Other Additions-Proved Developed Reserves. Developed activity for 2018 included the addition 7.9 MMBoe of developed reserves related to 17 gross (9.2 net) newly-drilled wells.

Extensions, Discoveries and Other Additions-PUDs. PUD activity was comprised primarily of 20.1 MMBoe of PUD reserves related to 16 gross (15.0 net) PUD locations in the Delaware Basin.

Acquisitions of Reserves-Proved Developed Reserves. Proved developed reserves acquired in various acreage swaps and an acquisition were 8.8 MMBoe during 2018.

Acquisitions of Reserves-PUDs. We acquired 47.6 MMBoe and 4.0 MMBoe of PUD reserves in 2018 in acreage swaps and an acquisition, respectively.

Dispositions-Proved Developed Reserves. Dispositions of 4.5 MMBoe were related to a divestiture and acreage surrendered in various acreage swaps.

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Dispositions-PUDs. Dispositions of 6.6 MMBoe reflect that we primarily divested proved acreage with future locations that were not in our five-year drilling plan as of December 31, 2017 in the acreage swap transactions.
At December 31, 2017, we projected a PUD reserve conversion rate of 16 percent for 2018. During 2018, a larger number of wells were turned-in-line than we anticipated, resulting in an actual conversion rate of 19 percent. We converted 58.3 MMBoe of PUD reserves at December 31, 2017 to proved developed reserves as of December 31, 2018.
Based on economic conditions on December 31, 2018, our approved development plan provides for the development of our remaining PUD locations within five years of the date such reserves were initially recorded. As of December 31, 2018, our 2019 PUD reserve conversion rate is expected to be approximately 16 percent. The balance of the PUD reserves are scheduled to be developed over the remaining four years in accordance with our current development plan. The level of capital spending necessary to achieve this drilling schedule is consistent with our recent performance and our outlook for future development activities.

2017 Activity. During 2017, we increased proved reserves by 111.5 MMBoe, or 33 percent, relative to December 31, 2016. The increase in proved reserves was primarily a result of an increase in acquisitions and reserve additions on proved acreage in the Delaware Basin from our 2017 development plan. In 2017, we produced 31.8 MMboe.

Revisions of Previous Estimates-Proved Developed Reserves. Proved developed reserves experienced a net positive revision of 17.7 MMBoe due to an increase in prices for crude oil, natural gas and NGLs and net positive revisions of 0.6 MMBoe reflecting changes in operating costs, performance revisions and other items.

Revisions of Previous Estimates-PUDs. Upward revisions to our PUD reserves were related to an increase of 89.8 MMBoe reflecting newly-booked locations on proven acreage resulting from our drilling activities. Partially offsetting this increase was a negative revision of 58.5 MMBoe in the Wattenberg Field due to drilling schedule changes and updated timing for development of certain locations exceeding the five-year rule. Drilling schedule changes, primarily related to 2017 acreage swaps, resulted in these locations being reclassified from proved to unproved status. All other changes were due to commodity pricing, lease operating expenses and other, which resulted in further upward revisions of 2.9 MMBoe of PUD reserves.

Extensions, Discoveries and Other Additions-Proved Developed Reserves. Developed additions for 2017 included the addition of 2.3 MMBoe of developed reserves related to newly-drilled wells.

Extensions, Discoveries and Other Additions-PUDs. PUD activity was comprised primarily of 3.7 MMBoe of PUD reserves related to PUD locations in the Delaware Basin.
Acquisitions of Reserves-Proved Developed Reserves. Proved developed reserves acquired in various acreage swaps were 1.3 MMBoe during 2017.
Acquisitions of Reserves-PUDs. We acquired 85.5 MMBoe of PUD reserves in 2017 in acreage swaps.
Dispositions-Proved Developed Reserves. Dispositions were related to acreage surrendered in various acreage swaps.
Dispositions-PUDs. Dispositions of PUDs were 1.9 MMBoe, reflecting the fact that we primarily divested proved acreage with future locations that were not in our five-year drilling plan as of December 31, 2016 in the acreage swap transactions.
2016 Activity. During 2016, we increased proved reserves by 68.6 MMBoe, or 25 percent, relative to December 31, 2015. This proved reserve increase was primarily a result of the development of longer lateral length well bores in the Wattenberg Field, which was driven by technology advancements, together with the ability to consolidate our leasehold position to drill longer length laterals with increased working interests. We also acquired proved developed reserves and undeveloped reserves in the Delaware Basin.

Revisions of Previous Estimates-Proved Developed Reserves. Proved developed reserves experienced a net positive revision of 2.6 MMBoe due to a decrease in operating costs and a net positive revision of 3.5 MMBoe for performance revisions and other items. These net positive revisions were partially offset by a decrease in prices for crude oil, natural gas and NGLs.

Revisions of Previous Estimates-PUDs. Downward revisions to our PUD reserves were related to a decrease of 61.0 MMBoe in the Wattenberg Field due to drilling schedule changes and updated timing for development of certain locations

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exceeding the five-year rule. Drilling schedule changes, primarily related to 2016 acreage swaps, resulted in these locations being reclassified from proved to unproved status. Partially offsetting this decrease was a positive revision of 10.8 MMBoe reflecting newly-booked locations on proven acreage resulting from our drilling activities. All other changes were due to commodity pricing, lease operating expenses and other, which resulted in further downward revisions of 1.5 MMBoe of PUD reserves.

Extensions, Discoveries and Other Additions-Proved Developed Reserves. Developed additions for 2016 included the addition 1.5 MMBoe of developed reserves related to newly-drilled wells.

Acquisitions of Reserves-Proved Developed Reserves. Proved developed reserves acquired in various acreage swaps and an acquisition were 10.2 MMBoe during 2016.

Acquisitions of Reserves-PUDs. We acquired 98.1 MMBoe and 25.3 MMBoe of PUD reserves in 2016 in acreage swaps and an acquisition, respectively.

Dispositions-Proved Developed Reserves. Dispositions of 0.1 MMBoe were related to acreage surrendered in various acreage swaps.
Dispositions-PUDs. Dispositions of PUDs were 1.6 MMBoe, reflecting the fact that we primarily divested proved acreage with future locations that were not in our five-year drilling plan as of December 31, 2015 in the acreage swap transactions.

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Results of Operations for Crude Oil and Natural Gas Producing Activities

The results of operations for crude oil and natural gas producing activities are presented below.

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Revenue:			
Crude oil, natural gas and NGLs sales	$1,389,961	$913,084	$497,353
Commodity price risk management gain (loss), net	145,237	(3,936)	(125,681)
	1,535,198	909,148	371,672
Expenses:			
Lease operating expenses	130,957	89,641	59,950
Production taxes	90,357	60,717	31,410
Transportation, gathering and processing expenses	37,403	33,220	18,415
Exploration expense	6,204	47,334	4,669
Impairment of properties and equipment	458,397	285,887	9,973
Depreciation, depletion and amortization	551,265	462,482	413,105
Accretion of asset retirement obligations	5,075	6,306	7,080
(Gain) loss on sale of properties and equipment	394	(766)	(43)
	1,280,052	984,821	544,559
Results of operations for crude oil and natural gas producing activities before provision for income taxes	255,146	(75,673)	(172,887)
Income tax (expense) benefit	(185,667)	47,247	64,733
Results of operations for crude oil and natural gas producing activities, excluding corporate overhead and interest costs	$69,479	$(28,426)	$(108,154)

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including costs such as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance, production and severance taxes and associated administrative expenses. DD&A expense includes those costs associated with capitalized acquisition, exploration and development costs, but does not include the depreciation applicable to support equipment. The provision for income taxes is computed using effective tax rates.

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Costs Incurred in Crude Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in crude oil and natural gas property acquisition, exploration and development are presented below.

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Acquisition of properties: (1)			
Proved properties	$205,253	$172	$268,567
Unproved properties	5,477	18,914	1,843,985
Development costs (2)	970,970	688,165	383,336
Exploration costs: (3)			
Exploratory drilling	36,704	80,103	—
Geological and geophysical	3,401	3,881	4,669
Total costs incurred (4)	$1,221,805	$791,235	$2,500,557

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(1) Property acquisition costs represent costs incurred to purchase, lease or otherwise acquire a property. Proved properties include approximately $40.9 million of infrastructure and pipeline costs in 2016.

(2) Development costs represent costs incurred to gain access to and prepare development well locations for drilling, drill and equip development wells, recomplete wells and provide facilities to extract, treat, gather and store crude oil, natural gas and NGLs. Of these costs incurred for the years ended December 31, 2018, 2017 and 2016, $438.4 million, $463.4 million and $204.6 million, respectively, were incurred to convert proved undeveloped reserves to proved developed reserves from the prior year end. These costs also include approximately $74.6 million and $32.8 million of infrastructure and pipeline costs in 2018 and 2017, respectively.

(3) Exploration costs represent costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing crude oil, natural gas and NGLs. These costs include, but are not limited to, dry hole contributions and costs of drilling and equipping exploratory wells.

(4) During 2017, we finalized our purchase price allocation for the 2016 Delaware Basin acquisition within the one year measurement period. The finalization included a reduction to our proved undeveloped and development costs of $24.6 million. We excluded this reduction from our 2017 costs incurred as it did not relate to any cash acquisitions in 2017.

Capitalized Costs Related to Crude Oil and Natural Gas Producing Activities

Aggregate capitalized costs related to crude oil and natural gas exploration and production activities with applicable accumulated DD&A are presented below:

	As of December 31,	
	2018	2017
	(in thousands)	
Proved crude oil and natural gas properties	$5,452,613	$4,356,922
Unproved crude oil and natural gas properties	492,594	1,097,317
Uncompleted wells, equipment and facilities	332,264	265,526
Capitalized costs	6,277,471	5,719,765

Less accumulated DD&A	(2,341,897)	(1,803,847)
Capitalized costs, net	$3,935,574	$3,915,918

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Reserves

The standardized measure below has been prepared in accordance with U.S. GAAP. Future estimated cash flows were based on a 12-month average price calculated as the unweighted arithmetic average of the prices on the first day of each month, January through December, applied to our year-end estimated proved reserves. Prices for each of the three years were adjusted by field for Btu content, transportation and regional price differences; however, they were not adjusted to reflect the value of our commodity derivatives. Production and development costs were based on prices as of December 31 for each of the respective years presented. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses, debt service or to depreciation, depletion and amortization expense. Production and development costs include those cash flows associated with the expected ultimate settlement of our asset retirement obligations. Future

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estimated income tax expense is computed by applying the statutory rate in effect at the end of each year to the projected future pre-tax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

The following table presents information with respect to the standardized measure of discounted future net cash flows relating to proved reserves. Changes in the demand for crude oil, natural gas and NGLs, inflation and other factors make such estimates inherently imprecise and subject to substantial revision. This table should not be construed to be an estimate of the current market value of our proved reserves.

	As of December 31,		
	2018	2017	2016
	(in thousands)		
Future estimated cash flows	$17,554,880	$12,340,407	$7,122,525
Future estimated production costs*	(4,782,948)	(3,245,627)	(1,624,167)
Future estimated development costs	(3,632,822)	(2,893,335)	(2,219,914)
Future estimated income tax expense	(1,404,121)	(748,494)	(597,476)
Future net cash flows	7,734,989	5,452,951	2,680,968
10% annual discount for estimated timing of cash flows	(3,287,273)	(2,572,846)	(1,260,339)
Standardized measure of discounted future estimated net cash flows	$4,447,716	$2,880,105	$1,420,629

* Represents future estimated lease operating expenses, production taxes and transportation, gathering and processing expenses.

The following table presents the principal sources of change in the standardized measure of discounted future estimated net cash flows:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Beginning of period	$2,880,105	$1,420,629	$1,096,864
Sales of crude oil, natural gas and NGLs production, net of production costs	(1,131,244)	(729,506)	(387,576)
Net changes in prices and production costs (1)	936,077	841,713	(205,760)
Extensions, discoveries and improved recovery, less related costs	190,084	47,240	15,128
Sales of reserves	(42,362)	(2,613)	(3,745)
Purchases of reserves	467,807	224,483	487,636
Development costs incurred during the period	462,088	419,047	268,672
Revisions of previous quantity estimates	631,198	484,431	(320,286)
Changes in estimated income taxes	(232,002)	(138,560)	(13,630)
Net changes in future development costs	(123,663)	25,183	391,145
Accretion of discount	583,744	167,487	133,747
Timing and other	(174,116)	120,571	(41,566)
End of period	$4,447,716	$2,880,105	$1,420,629

(1) Our weighted-average price, net of production costs per Boe, in our 2018 reserve report increased to $23.44 as compared to $20.08 for 2017 and $15.73 for 2016.

The data presented should not be viewed as representing the expected cash flows from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the recent average prices and current costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

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QUARTERLY FINANCIAL INFORMATION - UNAUDITED

Quarterly financial data for the years ended December 31, 2018 and 2017 is presented below. The quarterly consolidated statements of operations below reflect our revised presentation. The sum of the quarters may not equal the total of the year's net income or loss per share due to changes in the weighted-average shares outstanding throughout the year.

	2018 Quarter Ended			
	March 31 (1)	June 30	September 30 (1)	December 31 (1)
	(in thousands, except per share data)			
Total revenues	$260,600	$212,531	$280,717	$794,811
Total costs, expenses and other	260,924	400,770	270,593	538,626
Income (loss) from operations	(324)	(188,239)	10,124	256,185
Income (loss) before income taxes	(17,705)	(205,580)	(7,310)	238,024
Net income (loss)	$(13,139)	$(160,257)	$(3,434)	$178,853
Earnings per share:				
Basic	$(0.20)	$(2.43)	$(0.05)	$2.71
Diluted	(0.20)	(2.43)	(0.05)	2.71

	2017 Quarter Ended			
	March 31	June 30	September 30 (1)	December 31 (2)
	(in thousands, except per share data)			
Total revenues	$273,707	$275,158	$183,235	$189,516
Total costs, expenses and other	182,004	190,522	579,326	208,016
Income (loss) from operations	91,703	84,636	(396,091)	(18,500)
Income (loss) before income taxes	72,476	65,787	(414,887)	62,808
Net income (loss)	$46,146	$41,250	$(292,537)	$77,637
Earnings per share:				
Basic	$0.70	$0.63	$(4.44)	$1.18
Diluted	0.70	0.62	(4.44)	1.17

(1) Impairment charges, which are included in total costs, expenses and other above, reflect the correction of two errors in the timing of the reporting of certain impairments. In 2018, we corrected an error in our calculation of unproved properties and goodwill originally recorded in 2017, resulting in an additional impairment charge of $6.3 million being recorded during the three months ended March 31, 2018. Further, during the fourth quarter of 2018, we corrected for an additional $8.4 million impairment of unproved properties relating to the three months ended September 30, 2018. See the footnote titled Properties and Equipment to our consolidated financial statements included elsewhere in this report.

(2) Net income of $77.6 million for the quarter ended December 31, 2017 is primarily due to an income tax benefit of $114.4 million resulting from a decrease in deferred tax assets and liabilities related to the 2017 Tax Act.

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FINANCIAL STATEMENT SCHEDULE

Schedule II -VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance January 1,	Charged to Costs and Expenses	Deductions (1)	Ending Balance December 31,
	(in thousands)			
2018:				
Allowance for doubtful accounts	$3,128	$ 1,276	$ 23	$ 4,381
Allowance for expirations of unproved crude oil and natural gas properties	251,159	388,068	96,518	542,709
2017:				
Allowance for uncollectible notes	$44,038	$ —	$ 44,038	$ —
Allowance for doubtful accounts	2,190	1,108	170	3,128
Allowance for expirations of unproved crude oil and natural gas properties	359	263,817	13,017	251,159
2016:				
Allowance for uncollectible notes	$—	$ 44,038	$ —	$ 44,038
Allowance for doubtful accounts	2,009	1,309	1,128	2,190
Allowance for expirations of unproved crude oil and natural gas properties	144	215	—	359

(1) For allowance for uncollectible notes, deductions represent reversals of allowances due to the collection of amounts owed. For allowance for doubtful accounts, deductions represent the write-off of accounts receivable deemed uncollectible. For allowance for expirations of unproved crude oil and natural gas properties, deductions represent actual expired or abandoned unproved crude oil and natural gas properties, with a corresponding decrease to the historical cost of the associated asset.

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, 2018, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. Based on the results of this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were not effective as of December 31, 2018 because of the material weaknesses in our internal control over financial reporting described below.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting is a process designed by, or under the supervision of, our CEO and CFO, or persons performing similar functions, and effected by our board of directors, management and other personnel 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.

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 policies or procedures may deteriorate.

Management has assessed the effectiveness of our internal control over financial reporting as of December 31, 2018, based upon the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

We did not maintain a sufficient complement of personnel within the Land Department as a result of increased volume of leases, which contributed to the ineffective design and maintenance of controls to verify the completeness and accuracy of land administrative records associated with unproved leases, which are used in verifying the completeness, accuracy, valuation, rights and obligations over the accounting of properties and equipment, sales and accounts receivable and costs and expenses. These control deficiencies resulted in immaterial adjustments to our unproved properties, impairment of unproved properties, sales, accounts receivable and depletion expense accounts and related disclosures in our consolidated financial statements for the years ended December 31, 2018 and 2017. Additionally, these control deficiencies could result in misstatements of substantially all accounts and disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, our management has determined that these control deficiencies constitute material weaknesses.

Because of these material weaknesses, management concluded that we did not maintain effective internal control over financial reporting as of December 31, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears under Item 8.

Remediation Plan for Material Weaknesses

We are committed to continuing to review, optimize and enhance our internal control over financial reporting. In response to the identified material weaknesses, our management, with the oversight of the Audit Committee of our Board of

Directors, has assessed a number of different remediation initiatives to improve our internal control over financial reporting. Building on our efforts during 2017, we continued throughout 2018 to dedicate significant resources and efforts to improve our internal control over financial reporting and to take steps to remediate the material weaknesses identified above. While certain remediation plans have been implemented, we continue to actively plan for and implement additional remediation measures.

During 2018, we have taken steps to strengthen the control activities within the Land Department, which include the combination of hiring of additional personnel with relevant experience, increased layers of supervision, and division of responsibilities within the Land Department. We have also designed and implemented control activities to verify the completeness and accuracy of land administrative records associated with unproved leases, including the verification of the reliability of underlying data used in the execution of the control activities. As we continue to evaluate and work to improve our internal control over financial reporting, we may take additional measures to address these control deficiencies, or we may modify certain of the remediation measures described above to improve the operating effectiveness of those measures. These material weaknesses will not be considered remediated until the applicable remediated controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2019 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 11. EXECUTIVE COMPENSATION

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2019 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2019 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2019 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2019 Annual Stockholders' meeting and is incorporated by reference in this report.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a)(1) Exhibits:
See Exhibits Index on the following page.

ITEM 16. FORM 10-K SUMMARY

None.
Exhibits Index

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
2.1	Plan of Conversion, dated June 5, 2015, by PDC Energy, Inc. (the "Company").	8-K12B	001-37419	2.1	6/8/2015	
2.2	Stock Purchase and Sale Agreement, dated August 23, 2016, by and among the seller parties thereto, Kimmeridge Energy Management Company GP, LLC, Arris Petroleum Corporation and PDC Energy, Inc.	8-K	001-37419	2.1	8/24/2016	
2.3	Asset Purchase and Sale Agreement, dated August 23, 2016, by and among 299 Resources, LLC, 299 Production, LLC, 299 Pipeline, LLC, Kimmeridge Energy Management Company GP, LLC and PDC Energy, Inc.	8-K	001-37419	2.2	8/24/2016	
3.1	Certificate of Incorporation of the Company.	8-K12B	001-37419	3.1	6/8/2015	
3.2	By-laws of the Company.	8-K12B	001-37419	3.2	6/8/2015	
4.1	Form of Common Stock Certificate of the Company.	10-K	001-37419	4.1	2/28/2017	
4.2	Indenture, dated as of November 29, 2017, by and between PDC Energy, Inc., PDC Permian, Inc., a subsidiary guarantor of the Company, and U.S. Bank Trust National Association, as Trustee, relating to the 5.750% Senior Notes due 2026.	8-K	001-37419	4.1	11/29/2017	
4.3	Base Indenture, dated as of September 14, 2016, by and between the Company and U.S. Bank Trust National Association, as Trustee.	8-K	001-37419	4.1	9/14/2016	
4.4	First Supplemental Indenture, dated as of September 14, 2016, by and between the Company and U.S. Bank Trust National Association, as Trustee, relating to the 1.125% Convertible Senior Notes due 2021.	8-K	001-37419	4.2	9/14/2016	
4.5	Indenture, dated as of September 15, 2016, by and between PDC Energy, Inc. and U.S. Bank Trust	8-K	001-37419	4.1	9/15/2016	

	National Association, as Trustee, relating to the 6.125% Senior Notes due 2024.				
10.1	Form of Indemnification Agreement.	8-K	000-07246	10.1	6/8/2015
10.2	401(k) and Profit Sharing Plan, as amended on January 4, 2016.	10-K	001-37419	10.2	2/28/2017
10.3	Amended and Restated Non-Employee Director Deferred Compensation Plan.	10-K	001-37419	10.3	2/27/2018
10.4	2004 Long-Term Equity Compensation Plan amended and restated as of March 8, 2008 ("2004 Plan").	10-K	000-07246	10.26	2/27/2009
10.4.1	Summary of 2010 Stock Appreciation Rights and Restricted Stock Awards under the 2004 Plan.	8-K	000-07246		4/23/2010
10.5	Amended and Restated 2010 Long-Term Equity Compensation Plan, as amended.	10-K	001-37419	10.5	2/22/2016
10.6	Executive Severance Compensation Plan, as amended.	10-K	001-37419	10.6	2/22/2016
10.7	Form of 2011 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.2	2/21/2014
10.7.1	Form of 2013 Performance Share Agreement.	10-K	000-07246	10.9	2/27/2013
10.7.2	Form of 2013 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.10	2/27/2013
10.7.3	Form of 2014 Performance Share Agreement.	10-K	000-07246	10.5.4	2/19/2015
10.7.4	Form of 2014 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.5	2/19/2015

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
10.7.5	Form of 2015 Performance Share Agreement.	10-K	000-07246	10.5.6	2/19/2015	
10.7.6	Form of 2015 Restricted Stock Unit Agreement.	10-K	000-07246	10.5.7	2/19/2015	
10.7.7	Form of 2015 Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.8	2/19/2015	
10.7.8	Form of 2016 Performance Share Agreement.	10-K	001-37419	10.7.8	2/22/2016	
10.7.9	Form of 2018 Performance Share Agreement.	10-Q	001-37419	99.1	5/3/2018	
10.7.10	Form of 2018 Restricted Stock Unit Agreement (Executives).	10-Q	001-37419	99.2	5/3/2018	
10.7.11	Form of 2018 Restricted Stock Unit Agreement (Directors).	10-Q	001-37419	99.3	5/3/2018	
10.9	Employment Agreement with Daniel W. Amidon, General Counsel and Corporate Secretary, dated as of April 19, 2010.	8-K	000-07246	10.3	4/23/2010	
10.9.1	General Release of Claims, dated as of January 7, 2019 by and between PDC Energy, Inc. and Daniel W. Amidon.					X
10.10	Employment Agreement with Lance A. Lauck, Senior Vice President of Business Development, dated as of April 19, 2010.	8-K	000-07246	10.4	4/23/2010	
10.11	Fourth Amended and Restated Credit Agreement, dated as of May 23, 2018, among PDC Energy, Inc. as Borrower, each of the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent for the Lenders.	8-K	001-37419	10.1	5/25/2018	
10.12	Change of Control and Severance Plan.	10-K	001-37419	10.14	2/28/2017	
10.12.1	Amendment to the PDC Energy Change of Control and Severance Plan.	10-K	001-37419	10.14.1	2/28/2017	
10.13	2018 Equity Incentive Plan.	8-K	001-37419	10.1	5/31/2018	
10.14	General Release of Claims dated as of February 5, 2018, by and between PDC Energy, Inc. and David W. Honeyfield.	8-K	001-37419	10.1	2/9/2018	

10.15	Investment Agreement, dated December 6, 2016, by and among the Investor parties identified therein and PDC Energy, Inc. (relating to the Stock Purchase and Sale Agreement).	8-K	001-37419	10.1	12/7/2016	
10.16	Investment Agreement, dated December 6, 2016, by and among the Investor parties identified therein and PDC Energy, Inc. (relating to the Asset Purchase and Sale Agreement).	8-K	001-37419	10.2	12/7/2016	
21.1	Subsidiaries.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of Ryder Scott Company, L.P., Petroleum Consultants.					X
23.3	Consent of Netherland, Sewell & Associates, Inc., Petroleum Consultants.					X
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1*	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					
99.1	Report of Independent Petroleum Consultants - Ryder Scott Company, L.P.					X

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
99.2	Report of Independent Petroleum Consultants - Netherland, Sewell & Associates, Inc.					X
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X

* Furnished herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PDC ENERGY, INC.

By: /s/ Barton Brookman
Barton Brookman
President and Chief Executive Officer

February 27, 2019

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

Signature	Title	Date
/s/ Barton Brookman Barton Brookman	President, Chief Executive Officer and Director (principal executive officer)	February 27, 2019
/s/ R. Scott Meyers R. Scott Meyers	Senior Vice President and Chief Financial Officer (principal financial officer)	February 27, 2019
/s/ Douglas Griggs Douglas Griggs	Chief Accounting Officer (principal accounting officer)	February 27, 2019
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Chairman and Director	February 27, 2019
/s/ Anthony J. Crisafio Anthony J. Crisafio	Director	February 27, 2019
/s/ Larry F. Mazza Larry F. Mazza	Director	February 27, 2019
/s/ David C. Parke David C. Parke	Director	February 27, 2019
/s/ Randy S. Nickerson Randy S. Nickerson	Director	February 27, 2019
/s/ Mark E. Ellis Mark E. Ellis	Director	February 27, 2019
/s/ Christina M. Ibrahim Christina M. Ibrahim	Director	February 27, 2019

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GLOSSARY OF UNITS OF MEASUREMENT AND INDUSTRY TERMS

UNITS OF MEASUREMENT

The following presents a list of units of measurement used throughout the document.

Bbl – One barrel of crude oil or NGL or 42 gallons of liquid volume.
Bcf – One billion cubic feet of natural gas volume.
Boe – One barrel of crude oil equivalent.
Btu – British thermal unit.
BBtu – One billion British thermal units.
MBoe – One thousand barrels of crude oil equivalent.
MBbls – One thousand barrels of crude oil.
Mcf – One thousand cubic feet of natural gas volume.
MMBoe – One million barrels of crude oil equivalent.
MMBbls – One million barrels of crude oil.
MMBtu – One million British thermal units.
MMcf – One million cubic feet of natural gas volume.

GLOSSARY OF INDUSTRY TERMS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report:

CIG - Colorado Interstate Gas.

Completion - Refers to the installation of permanent equipment for the production of crude oil and natural gas from a recently drilled well or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

Developed acreage - Acreage assignable to productive wells.

Development well - A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differentials - The difference between the crude oil and natural gas index spot price and the corresponding cash spot price in a specified location.

Dry well or dry hole - A well found to be incapable of producing hydrocarbons in sufficient quantities to justify completion as an oil or gas well.

Exploratory well - A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Extensions, discoveries and other additions - As to any period, the increases to proved reserves from all sources other than the acquisition of proved properties or revisions of previous estimates.

Farm-out - Transfer of all or part of the operating rights from a working interest owner to an assignee, who assumes all or some of the burden of development in return for an interest in the property. The assignor usually retains an overriding royalty interest but may retain any type of interest.

Fracture or Fracturing - Procedure to stimulate production by forcing a mixture of fluid and proppant into the formation under high pressure. Fracturing creates artificial fractures in the reservoir rock to increase permeability and porosity, thereby allowing the release of trapped hydrocarbons.

Gross acres or wells - Refers to the total acres or wells in which we have a working interest.

Henry Hub - Refers to the pricing point for natural gas futures contracts traded on NYMEX.

Horizontal drilling - A drilling technique that permits the operator to drill a horizontal well shaft from the bottom of a vertical well and thereby to contact and intersect a larger portion of the producing horizon than conventional vertical drilling techniques and may, depending on the horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

Joint interest billing - Process of billing/invoicing the costs related to well drilling, completions and production operations among working interest partners.

Natural gas liquid(s) or NGL(s) - Hydrocarbons which can be extracted from natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs include ethane, propane, butane and other natural gasolines.

Net acres or wells - Refers to gross acres or wells we own multiplied, in each case, by our percentage working interest. References to net acres or wells include our proportionate share of PDCM's and our affiliated partnerships' net acres or wells.

Net production - Crude oil and natural gas production that we own, less royalties and production due to others.

Non-operated - A project in which we are not the operator.

NYMEX - New York Mercantile Exchange.

Operator - The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

Overriding royalty - An interest which is created out of the operating or working interest. Its term is coextensive with that of the operating interest.

Possible reserves - This term is defined in the SEC Regulation S-X Section 4-10(a) and refers to those reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability to exceed the sum of proved, probable and possible reserves. When probabilistic methods are used, there must be at least a 10 percent probability that the actual quantities recovered will equal or exceed the sum of proved, probable and possible estimates.

Present value of future net revenues or (PV-10) - The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, of proved reserves calculated in accordance with Financial Accounting Standards Board guidelines, net of estimated production and future development costs, using pricing and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization and discounted using an annual discount rate of 10 percent. PV-10 is pre-tax and therefore a non-U.S. GAAP financial measure.

Probable reserves - This term is defined in the SEC Regulation S-X Section 4-10(a) and refers to those reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. Similarly, when probabilistic methods are used, there must be at least a 50 percent probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

Productive well - An exploratory or developmental well that is not a dry well or dry hole, as defined above.

Proved developed non-producing reserves - Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and/or (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed producing reserves or PDPs - Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

Proved developed reserves - The combination of proved developed producing and proved developed non-producing reserves.

Proved reserves - This term means "proved oil and gas reserves" as defined in SEC Regulation S-X Section 4-10(a) and refers to those quantities of crude oil and condensate, natural gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, and under existing conditions, operating methods and government regulations - prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved undeveloped reserves or PUDs - Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Recomplete or Recompletion - The modification of an existing well for the purpose of producing crude oil and natural gas from a different producing formation.

Reserves - Estimated remaining quantities of crude oil, natural gas, NGLs and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering crude oil, natural gas and NGLs or related substances to market, and all permits and financing required to implement the project.

Royalty - An interest in a crude oil and natural gas lease or mineral interest that gives the owner of the royalty the right to receive a portion of the production from the leased acreage or mineral interest (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner’s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Section - A square tract of land one mile by one mile, containing 640 acres.

Spud - To begin drilling; the act of beginning a hole.

Standardized measure of discounted future net cash flows or standardized measure - Future net cash flows discounted at a rate of 10 percent. Future net cash flows represent the estimated future revenues to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, giving effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment and (ii) future income tax expense.

Stratigraphic test well - A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production.

Undeveloped acreage - Leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas, regardless of whether such acreage contains proved reserves.

Waha - Waha West Texas natural gas prices

Working interest - An interest in a crude oil and natural gas lease that gives the owner of the interest the right to drill and produce crude oil and natural gas on the leased acreage. It requires the owner to pay its share of the costs of drilling and production operations.

Workover - Major remedial operations on a producing well to restore, maintain, or improve the well's production.

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