PDC ENERGY, INC.
Form 10-Q
November 06, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 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

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

Indicate by check mark whether the registrant has submitted electronically 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 x No o

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 o	Smaller reporting company o
	Emerging growth company o

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 66,080,471 shares of the Company's Common Stock ($0.01 par value) were outstanding as of October 22, 2018.

PDC ENERGY, INC.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act"), Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") and the United States ("U.S.") Private Securities Litigation Reform Act of 1995 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 the anticipated capital expenditure outspend for 2018; management of lease expiration issues; financial ratios and compliance with covenants in our revolving credit facility; impacts of certain accounting and tax changes; midstream capacity and related curtailments; fractionation capacity; impacts of Proposition 112 and other 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, including the impact of having a new plant come online during the third quarter of 2018.

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 our 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 worldwide production volumes and demand, including economic conditions that might impact demand and prices for the products we produce;
- volatility of commodity prices for crude oil, natural gas and natural gas liquids ("NGLs") and the risk of an extended period 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 of 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 reserve estimates and expected 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;
- increases or changes in costs and expenses;
- 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 adverse changes in construction and procurement costs associated with future build out of midstream-related assets;
- future cash flows, liquidity and financial condition;
- competition within the oil and gas industry;
- availability and cost of capital;

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- our success in marketing crude oil, natural gas and NGLs;
- effect of crude oil and natural gas derivative 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 the heading "Risk Factors," made in this Quarterly Report on Form 10-Q, our Annual Report on Form 10-K for the year ended December 31, 2017 filed with the U.S. Securities and Exchange Commission ("SEC") on February 27, 2018 and as amended on May 1, 2018 (the "2017 Form 10-K"), and our other filings with the SEC for further information on risks and uncertainties that could affect our business, financial condition, results of operations and prospects, which are incorporated by this reference as though fully set forth herein. We caution you not to place undue reliance on the 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.

REFERENCES

Unless the context otherwise requires, references in this report to "PDC Energy," "PDC," "the Company," "we," "us," "our" or "ours" refer to the registrant, PDC Energy, Inc. and all 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.

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	September 30, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 1,369	$ 180,675
Accounts receivable, net	241,155	197,598
Fair value of derivatives	7,555	14,338
Prepaid expenses and other current assets	6,713	8,613
Total current assets	256,792	401,224
Properties and equipment, net	4,309,021	3,933,467
Assets held-for-sale, net	—	40,084
Fair value of derivatives	3,949	—
Other assets	31,462	45,116
Total Assets	$ 4,601,224	$ 4,419,891
Liabilities and Stockholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 251,081	$ 150,067
Production tax liability	59,539	37,654
Fair value of derivatives	205,013	79,302
Funds held for distribution	104,259	95,811
Accrued interest payable	15,425	11,815
Other accrued expenses	39,260	42,987
Total current liabilities	674,577	417,636
Long-term debt	1,234,733	1,151,932
Deferred income taxes	138,963	191,992
Asset retirement obligations	72,707	71,006
Fair value of derivatives	61,013	22,343
Other liabilities	76,987	57,333
Total liabilities	2,258,980	1,912,242
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 66,136,427 and 65,955,080 issued as of September 30, 2018 and December 31, 2017, respectively	661	659
Additional paid-in capital	2,514,861	2,503,294
Retained earnings (deficit)	(170,126)	6,704
Treasury shares - at cost, 62,265 and 55,927 as of September 30, 2018 and December 31, 2017, respectively	(3,152)	(3,008)

Total stockholders' equity	2,342,244	2,507,649
Total Liabilities and Stockholders' Equity	$ 4,601,224	$4,419,891

See accompanying Notes to Condensed Consolidated Financial Statements
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PDC ENERGY, INC.
Condensed Consolidated Statements of Operations
(unaudited; in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Revenues				
Crude oil, natural gas and NGLs sales	$372,439	$232,733	$1,003,597	$636,027
Commodity price risk management gain (loss), net	(94,394)	(52,178)	(257,760)	86,458
Other income	2,672	2,680	8,011	9,615
Total revenues	280,717	183,235	753,848	732,100
Costs, expenses and other				
Lease operating expenses	33,046	25,353	94,942	65,170
Production taxes	23,984	15,516	66,757	42,957
Transportation, gathering and processing expenses	9,234	9,794	25,511	22,184
Exploration, geologic and geophysical expense	1,032	41,908	4,553	43,895
Impairment of properties and equipment	1,488	252,740	194,230	282,499
Impairment of goodwill	—	75,121	—	75,121
General and administrative expense	48,240	29,299	121,183	85,145
Depreciation, depletion and amortization	147,540	125,238	409,952	360,567
Accretion of asset retirement obligations	1,200	1,472	3,773	4,906
(Gain) loss on sale of properties and equipment	2,118	(62)	3,199	(754)
Provision for uncollectible note receivable	—	—	—	(40,203)
Other expenses	2,711	2,947	8,187	10,365
Total costs, expenses and other	270,593	579,326	932,287	951,852
Income (loss) from operations	10,124	(396,091)	(178,439)	(219,752)
Interest expense	(17,622)	(19,275)	(52,561)	(58,359)
Interest income	188	479	405	1,487
Loss before income taxes	(7,310)	(414,887)	(230,595)	(276,624)
Income tax benefit	3,876	122,350	53,765	71,483
Net loss	$(3,434)	$(292,537)	$(176,830)	$(205,141)
Earnings per share:				
Basic	$(0.05)	$(4.44)	$(2.68)	$(3.12)
Diluted	$(0.05)	$(4.44)	$(2.68)	$(3.12)
Weighted-average common shares outstanding:				
Basic	66,073	65,865	66,032	65,825
Diluted	66,073	65,865	66,032	65,825

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Nine Months Ended September 30,	
	2018	2017
Cash flows from operating activities:		
Net loss	$(176,830)	$(205,141)
Adjustments to net loss to reconcile to net cash from operating activities:		
Net change in fair value of unsettled commodity derivatives	167,218	(64,307)
Depreciation, depletion and amortization	409,952	360,567
Impairment of properties and equipment	194,230	282,499
Impairment of goodwill	—	75,121
Exploratory dry hole costs	—	41,187
Provision for uncollectible notes receivable	—	(40,203)
Accretion of asset retirement obligations	3,773	4,906
Non-cash stock-based compensation	16,357	14,587
(Gain) loss on sale of properties and equipment	3,199	(754)
Amortization of debt discount and issuance costs	9,454	9,628
Deferred income taxes	(53,029)	(71,529)
Other	1,025	986
Changes in assets and liabilities	2,485	13,105
Net cash from operating activities	577,834	420,652
Cash flows from investing activities:		
Capital expenditures for development of crude oil and natural gas properties	(685,549)	(528,850)
Capital expenditures for other properties and equipment	(3,739)	(3,740)
Acquisition of crude oil and natural gas properties, including settlement adjustments	(181,572)	(14,482)
Proceeds from sale of properties and equipment	2,443	3,322
Proceeds from divestiture	43,493	—
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	(823,675)	(512,797)
Cash flows from financing activities:		
Proceeds from revolving credit facility	629,000	—
Repayment of revolving credit facility	(554,000)	—
Payment of debt issuance costs	(4,086)	—
Purchases of treasury shares	(4,700)	(5,325)
Other	(928)	(951)
Net cash from financing activities	65,286	(6,276)
Net change in cash, cash equivalents and restricted cash	(180,555)	(98,421)
Cash, cash equivalents and restricted cash, beginning of period	189,925	244,100
Cash, cash equivalents and restricted cash, end of period	$9,370	$145,679
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$39,470	$45,719

Income taxes	(6,707)	(2,623)
Non-cash investing and financing activities:		
Change in accounts payable related to capital expenditures	$91,444	$89,974
Change in asset retirement obligations, with a corresponding change to crude oil and natural gas properties, net of disposals	6,720	3,357
Purchase of properties and equipment under capital leases	1,253	3,363

See accompanying Notes to Condensed Consolidated Financial Statements

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PDC ENERGY, INC.
Condensed Consolidated Statement of Equity
(unaudited; in thousands, except share data)

	Common Stock			Treasury Stock			
	Shares	Amount	Additional Paid-in Capital	Shares	Amount	Retained Earnings (Deficit)	Total Stockholders' Equity
Balance, December 31, 2017	65,955,080	$ 659	$2,503,294	(55,927)	$(3,008)	$6,704	$2,507,649
Net loss	—	—	—	—	—	(176,830)	(176,830)
Purchase of treasury shares	—	—	—	(90,465)	(4,700)	—	(4,700)
Issuance of treasury shares	—	—	(4,698)	86,701	4,698	—	—
Non-employee directors' deferred compensation plan	—	—	—	(2,574)	(142)	—	(142)
Issuance of stock awards, net of forfeitures	181,347	2	(2)	—	—	—	—
Stock-based compensation expense	—	—	16,357	—	—	—	16,357
Other	—	—	(90)	—	—	—	(90)
Balance, September 30, 2018	66,136,427	$ 661	$2,514,861	(62,265)	$(3,152)	$(170,126)	$2,342,244

See accompanying Notes to Condensed Consolidated Financial Statements

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. 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 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 September 30, 2018, we owned an interest in approximately 3,000 gross productive 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 accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly-owned subsidiaries and our proportionate share of our affiliated partnerships. Pursuant to the proportionate consolidation method, our accompanying condensed consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the entities which we proportionately consolidate. All material intercompany accounts and transactions have been eliminated in consolidation.

In our opinion, the accompanying condensed consolidated financial statements contain all adjustments, consisting of normal recurring adjustments, necessary for a fair statement of our financial statements for interim periods in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. The December 31, 2017 condensed consolidated balance sheet data was derived from audited statements, but does not include all disclosures required by U.S. GAAP. The information presented in this Quarterly Report on Form 10-Q should be read in conjunction with our audited consolidated financial statements and notes thereto included in our 2017 Form 10-K. Our results of operations and cash flows for the nine months ended September 30, 2018 are not necessarily indicative of the results to be expected for the full year or any other future period.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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 condensed consolidated statements of cash flows. The following table provides a reconciliation of cash and cash equivalents and restricted cash reported on the condensed consolidated balance sheets at September 30, 2018 and 2017 and December 31, 2017, which sum to the total of cash, cash equivalents and restricted cash in the condensed consolidated statements of cash flows:

	September 30, 2018	December 31, 2017	September 30, 2017
	(in thousands)		
Cash and cash equivalents	$1,369	$ 180,675	$ 136,429
Restricted cash	8,001	9,250	9,250
Cash, cash equivalents and restricted cash shown in the condensed consolidated statements of cash flows	$9,370	$ 189,925	$ 145,679

Restricted cash is included in other assets on the condensed consolidated balance sheets at September 30, 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 effective July 1, 2018. Adoption of this standard did not have an impact on our condensed consolidated financial statements or related disclosures.

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. For leases with terms of more than 12 months, the accounting update requires lessees to recognize a right-of-use asset and lease liability for its right to use the underlying asset and the corresponding lease obligation. Both the lease asset and liability will initially be measured at the present value of the future minimum lease payments over the lease term. Subsequent measurement, including the presentation of expenses and cash flows, will depend upon the classification of the lease as either a finance or operating lease. The guidance is effective for fiscal years beginning after December 15, 2018, and interim periods within those years, with early adoption permitted, and is to be applied as of the beginning of the earliest period presented using a modified retrospective approach. The update does not apply to leases of mineral rights to explore for or use crude oil and natural gas. We are continuing to assess the full effect the guidance will have on our existing accounting policies and our condensed consolidated financial statements, and we expect there will be an increase in assets and liabilities on our condensed consolidated balance sheets at adoption due to the recording of right-of-use assets and corresponding lease liabilities.

In August 2017, the FASB issued an accounting update to provide guidance for various components of hedge accounting, including hedge ineffectiveness, the expansion of types of permissible hedging strategies, reduced complexity in the application of the long-haul method for fair value hedges and reduced complexity in assessment of effectiveness. The guidance is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, with early adoption permitted. We are currently evaluating the impact these changes may have on our condensed consolidated financial statements.

In August 2018, the FASB issued an accounting update for fair value disclosures that removes or modifies current disclosures and adds additional disclosures. The update to the guidance is the result of the FASB's test of the principles developed in its disclosure effectiveness project, which is designed to improve the effectiveness of disclosures in the notes to the financial statements. The disclosures that have been removed or modified may be applied immediately with retrospective application. The guidance for the additional disclosures is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, with early adoption permitted. We are currently evaluating the impact these changes may have on our condensed consolidated financial statements.

NOTE 3 - BUSINESS COMBINATION

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 September 2017. The $21.0 million deposit was included in other assets on our December 31, 2017 condensed consolidated balance sheet. We acquired approximately 7,400 net acres, approximately 220 gross drilling locations and 24 operated horizontal wells that were either drilled uncompleted wells ("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 current 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):

	September 30, 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 three and nine months ended September 30, 2018 have been included in our condensed consolidated financial statements, including approximately $19.8 million and $41.6 million, respectively, of total revenue, $11.6 million and $23.6 million, respectively, of income from operations and $0.18 and $0.36, respectively, 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 condensed consolidated financial statements for the three and nine months ended September 30, 2017.

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 $2.9 million and $8.2 million in the three and nine months ended September 30, 2017, respectively, 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 the three and nine months ended September 30, 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.

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 the three and nine months ended September 30, 2018 and 2017, 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.

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 the three and nine months ended September 30, 2018 and 2017 (in thousands):

	Three Months Ended September 30,			Nine Months Ended September 30,		
Revenue by Commodity and Operating Region	2018	2017 (1)	Percentage Change	2018	2017 (1)	Percentage Change
Crude oil						
Wattenberg Field	$216,346	$134,785	60.5 %	$576,645	$369,231	56.2 %
Delaware Basin	68,341	19,654	247.7 %	184,357	49,519	272.3 %
Utica Shale (2)	—	2,581	(100.0)%	2,696	10,067	(73.2)%
Total	$284,687	$157,020	81.3 %	$763,698	$428,817	78.1 %
Natural gas						
Wattenberg Field	$27,762	$32,919	(15.7)%	$80,174	$99,537	(19.5)%
Delaware Basin	6,994	7,627	(8.3)%	22,145	12,863	72.2 %
Utica Shale (2)	—	910	(100.0)%	1,109	4,330	(74.4)%
Total	$34,756	$41,456	(16.2)%	$103,428	$116,730	(11.4)%
NGLs						
Wattenberg Field	$36,758	$27,352	34.4 %	$95,799	$74,594	28.4 %
Delaware Basin	16,238	5,887	175.8 %	39,832	12,513	218.3 %
Utica Shale (2)	—	1,018	(100.0)%	840	3,373	(75.1)%
Total	$52,996	$34,257	54.7 %	$136,471	$90,480	50.8 %
Revenue by Operating Region						
Wattenberg Field	$280,866	$195,056	44.0 %	$752,618	$543,362	38.5 %
Delaware Basin	91,573	33,168	176.1 %	246,334	74,895	228.9 %
Utica Shale (2)	—	4,509	(100.0)%	4,645	17,770	(73.9)%
Total	$372,439	$232,733	60.0 %	$1,003,597	$636,027	57.8 %

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(1) As we have elected the modified retrospective method of adoption for the New Revenue Standard, revenues for

the three and nine months ended September 30, 2017 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/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 condensed 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 the nine months ended September 30, 2018:

	Amount (in thousands)
Beginning balance, January 1, 2018	$ 3,746
Additions	2,217
Amortized as a reduction to crude oil, natural gas and NGLs sales	(3,024)
Ending balance, September 30, 2018	$ 2,939

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 September 30, 2018 and December 31, 2017 was $199.5 million and $154.3 million, respectively. We did not record an allowance for doubtful accounts for these receivables at September 30, 2018 or December 31, 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 derivative instruments based upon 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, determination that the source of the inputs is valid, 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. While we use common industry practices to develop our valuation techniques and believe our valuation method is appropriate and consistent with those used by other market participants, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values.

Our crude oil and natural gas fixed-price swaps are included in Level 2 of the hierarchy. Our collars and propane fixed-price swaps are included in Level 3 of the hierarchy. Our basis swaps are included in Level 2 and Level 3 of the hierarchy. 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:

	September 30, 2018			December 31, 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	$5,843	$ 5,661	$11,504	$12,949	$ 1,389	$14,338
Total liabilities	(231,503)	(34,523)	(266,026)	(90,569)	(11,076)	(101,645)
Net liability	$(225,660)	$ (28,862)	$(254,522)	$(77,620)	$ (9,687)	$(87,307)

The following table presents a reconciliation of our Level 3 assets measured at fair value:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Fair value of Level 3 instruments, net asset (liability) beginning of period	$(19,100)	$8,619	$(9,687)	$(9,574)
Changes in fair value included in condensed consolidated statement of operations line item:				
Commodity price risk management gain (loss), net	(16,175)	(14,075)	(23,029)	8,547
Settlements included in condensed consolidated statement of operations line items:				
Commodity price risk management gain (loss), net	6,413	(1,013)	3,854	(5,442)
Fair value of Level 3 instruments, net liability end of period	$(28,862)	$(6,469)	$(28,862)	$(6,469)
Net change in fair value of Level 3 unsettled derivatives included in condensed consolidated statement of operations line item:				
Commodity price risk management gain (loss), net	$(7,451)	$(8,711)	$(4,229)	$(583)

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 this report.

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 proved crude oil and natural gas properties 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.

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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:

	As of September 30, 2018		As of December 31, 2017	
	Estimated Fair Value (in millions)	Percent of Par	Estimated Fair Value (in millions)	Percent of Par
Senior notes:				
2021 Convertible Notes	$194.2	97.1 %	$195.6	97.8 %
2024 Senior Notes	393.8	98.5 %	416.0	104.0 %
2026 Senior Notes	570.8	95.1 %	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.

Concentration of Risk

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 and natural gas. 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 September 30, 2018, taking into account the estimated likelihood of nonperformance.

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.

Cash and Cash Equivalents. We consider all highly liquid instruments purchased with an original maturity of three months or less to be cash equivalents. Cash and cash equivalents potentially subject us to a concentration of credit risk as substantially all of our deposits held in financial institutions were in excess of the FDIC insurance limits at September 30, 2018 and December 31, 2017. We maintain our cash and cash equivalents in the form of money market and checking accounts with financial institutions that we believe are creditworthy and are also major lenders under our revolving credit facility.

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 September 30, 2018, we had derivative instruments, which were comprised of collars, fixed-price swaps and basis protection swaps, in place for a portion of our anticipated 2018, 2019 and 2020 production. 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.

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As of September 30, 2018, we had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

Commodity/ Index/ Maturity Period	Collars			Fixed-Price Swaps		Fair Value September 30, 2018 (1) (in thousands)
	Quantity (Crude oil - MBls Natural Gas - BBtu)	Weighted-Average Contract Price		Quantity (Crude Oil - MBbls Gas and Basis-BBtu Propane - MBbls)	Weighted-Average Contract Price	
		Floors	Ceilings			
Crude Oil						
NYMEX						
2018	528	$ 45.59	$ 56.82	2,968	$ 52.23	$(69,943)
2019	2,600	56.54	68.13	8,400	53.86	(157,085)
2020	3,600	55.00	71.68	5,000	62.07	(30,034)
Total Crude Oil	6,728			16,368		$(257,062)
Natural Gas						
NYMEX						
2018	120	$ 3.00	$ 3.90	14,145	$ 2.93	$(1,504)
2019	—	—	—	8,004	2.78	(15)
Dominion South						
2018	—	—	—	94	2.12	6
2019	—	—	—	121	2.13	7
Columbia						
2018	—	—	—	3	2.40	$—
2019	—	—	—	3	2.40	—
Total Natural Gas	120			22,370		$(1,506)
Basis Protection - Crude Oil						
Midland Cushing						
2018	—	$ —	$ —	182	$ (0.10)	$1,713
Total Basis Protection - Crude Oil	—			182		$1,713
Basis Protection - Natural Gas						
CIG						
2018	—	$ —	$ —	9,806	$ (0.42)	$3,537
2019	—	—	—	7,924	(0.88)	(908)
Waha						

2018	—	—	—	1,713	(0.50)	1,862
Total Basis Protection - Natural Gas	—			19,443		$4,491
Propane						
Mont Belvieu						
2018	—	$ —	$ —	167	$ 33.97	$(1,938)
Total Propane	—			167		$(1,938)
Rollfactor (2)						
Crude Oil CMA						
2018	—	$ —	$ —	1,529	$ 0.14	$(220)
Total Rollfactor	—			1,529		$(220)
Commodity Derivatives Fair Value						$(254,522)

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(1) Approximately 49.2 percent of the fair value of our commodity derivative assets and 13.0 percent of the fair value of our commodity derivative liabilities were measured using significant unobservable inputs (Level 3).

(2) These positions hedge the timing risk associated with our physical sales. We generally sell crude oil for the delivery month at a sales price based on the average NYMEX West Texas Intermediate price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is the first month.

We have not elected to designate any of our derivative instruments as cash flow hedges; therefore, these instruments do not qualify for hedge accounting. Accordingly, changes in the fair value of our derivative instruments are recorded in the condensed consolidated statements of operations.

The following table presents the balance sheet location and fair value amounts of our derivative instruments on the condensed consolidated balance sheets:

Derivative Instruments:		Condensed Consolidated Balance Sheet Line Item	Fair Value September 30, 2018	December 31, 2017
			(in thousands)	
Derivative assets:	Current			
	Commodity derivative contracts	Fair value of derivatives	$433	$7,340
	Basis protection derivative contracts	Fair value of derivatives	7,111	6,998
	Rollfactor derivative contracts	Fair value of derivatives	11	—
			7,555	14,338
	Non-current			
	Commodity derivative contracts	Fair value of derivatives	3,949	—
Total derivative assets			$11,504	$14,338
Derivative liabilities:	Current			
	Commodity derivative contracts	Fair value of derivatives	$204,145	$77,999
	Basis protection derivative contracts	Fair value of derivatives	638	234
	Rollfactor derivative contracts	Fair value of derivatives	230	1,069
			205,013	79,302
	Non-current			
	Commodity derivative contracts	Fair value of derivatives	60,744	22,343
	Basis protection derivative contracts	Fair value of derivatives	269	—
			61,013	22,343
Total derivative liabilities			$266,026	$101,645

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

Condensed Consolidated Statement of Operations Line Item	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
	(in thousands)			
Commodity price risk management gain (loss), net				
Net settlements	$(48,096)	$9,585	$(90,542)	$22,151
Net change in fair value of unsettled derivatives	(46,298)	(61,763)	(167,218)	64,307

Total commodity price risk management gain (loss), net	$(94,394)	$(52,178)	$(257,760)	$86,458

Our decrease in net settlements for the nine months ended September 30, 2018 was partially offset by an $11.3 million realized gain on the early settlement of certain commodity derivative basis protection positions, including $10.3 million for the early settlement of crude oil basis protection instruments and $1.0 million for the early settlement of natural gas basis protection instruments, both for our Delaware Basin operations. The volumes associated with these instruments were impacted by certain marketing agreements entered into during the nine months ended September 30, 2018, which eliminated the underlying sale price variability, and therefore there was no longer a variable to hedge.

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 condensed consolidated balance sheets.

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

As of September 30, 2018	Derivative Instruments, Gross	Effect of Master Netting Agreements	Derivative Instruments, Net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$11,504	$ (11,451)	$ 53
Liability derivatives:			
Derivative instruments, at fair value	$266,026	$ (11,451)	$ 254,575

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

NOTE 7 - PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net of accumulated depreciation, depletion and amortization ("DD&A"):

	September 30, 2018	December 31, 2017
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$5,204,267	$4,356,922
Unproved	866,719	1,097,317
Total crude oil and natural gas properties	6,070,986	5,454,239
Infrastructure, pipeline and other	141,045	109,359
Land and buildings	12,544	10,960
Construction in progress	318,949	196,024
Properties and equipment, at cost	6,543,524	5,770,582
Accumulated DD&A	(2,234,503)	(1,837,115)
Properties and equipment, net	$4,309,021	$3,933,467

The following table presents impairment charges recorded for crude oil and natural gas properties:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Impairment of proved and unproved properties	$1,488	$252,623	$194,146	$282,188
Amortization of individually insignificant unproved properties	—	117	84	311
Impairment of crude oil and natural gas properties	$1,488	$252,740	$194,230	$282,499

During the nine months ended September 30, 2018, we recorded impairment charges totaling $194.2 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 intend to focus our future Delaware Basin development in our oilier core areas where we have identified approximately 450 mid-length lateral equivalent Wolfcamp drilling locations. 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.

Additionally, we corrected an error in our calculation of the unproved properties and goodwill impairment originally reported in the quarter ended September 30, 2017. The correction of the error resulted in an additional impairment charge of $6.3 million, recorded in the three months ended March 31, 2018, which we have included in the impairment of properties and equipment expense line in our condensed consolidated statement of operations. We evaluated the error 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 impact of the error did not have a material impact on our previously-issued financial statements or those of the period of correction.

Utica Shale Divestiture. In March 2018, we completed the disposition of our Utica Shale properties (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 the nine months ended September 30, 2018, which included post-closing adjustments. The divestiture of the Utica Shale properties 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.

Suspended Well Costs. During the three months ended September 30, 2018, we spud one well in the Delaware Basin for which we are unable to make a final determination regarding whether proved reserves can be associated with the well as of September 30, 2018 as the well had not been completed as of that date. Therefore, we have classified the capitalized costs of the well as suspended well costs as of September 30, 2018 while we continue to conduct completion and testing operations to determine the existence of proved reserves.

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

	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
	(in thousands, except for number of wells)	
Beginning balance	$15,448	$—
Additions to capitalized exploratory well costs pending the determination of proved reserves	29,203	51,776
Reclassifications to proved properties	(43,145)	(36,328)

Ending balance	$ 1,506	$ 15,448
Number of wells pending determination at period end	1	3

Acreage Exchange. In July 2018, we entered into an acreage exchange transaction that involved the consolidation of certain acreage positions in the core area of the Wattenberg Field. Upon closing, we received approximately 2,500 net acres and $3.7 million in cash in exchange for approximately 2,600 acres. The difference in the number of net acres was primarily due to variances in working and net revenue interests. Based upon our analysis of risk, timing and expected future cash flows, 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 costs were recorded at the previous historical cost of the assets we exchanged, less cash received.

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NOTE 8 - OTHER ACCRUED EXPENSES AND OTHER LIABILITIES

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

	September 30, 2018	December 31, 2017
	(in thousands)	
Employee benefits	$16,555	$ 22,383
Asset retirement obligations	16,006	15,801
Environmental expenses	3,415	1,374
Other	3,284	3,429
Other accrued expenses	$39,260	$ 42,987

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

	September 30, 2018	December 31, 2017
	(in thousands)	
Production taxes	$44,817	$ 50,476
Deferred oil gathering credit	22,613	—
Other	9,557	6,857
Other liabilities	$76,987	$ 57,333

Deferred Oil Gathering Credit. On January 31, 2018, we received a payment of $24.1 million from Saddle Butte Rockies Midstream, LLC 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 Saddle Butte'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 $0.4 million and $1.1 million for the three and nine months ended September 30, 2018 related to the deferred oil gathering credit are included as a reduction to transportation, gathering and processing expenses in our condensed consolidated statements of operations.

NOTE 9 - LONG-TERM DEBT

Long-term debt consisted of the following as of:

	September 30, 2018	December 31, 2017
	(in thousands)	
Senior notes:		
1.125% Convertible Notes due September 2021:		
Principal amount	$200,000	$200,000
Unamortized discount	(24,697)	(30,328)
Unamortized debt issuance costs	(2,884)	(3,615)
Net of unamortized discount and debt issuance costs	172,419	166,057
6.125% Senior Notes due September 2024:		
Principal amount	400,000	400,000
Unamortized debt issuance costs	(5,835)	(6,570)
Net of unamortized debt issuance costs	394,165	393,430
5.75% Senior Notes due May 2026:		
Principal amount	600,000	600,000
Unamortized debt issuance costs	(6,851)	(7,555)
Net of unamortized debt issuance costs	593,149	592,445
Total senior notes	1,159,733	1,151,932
Revolving credit facility due May 2023	75,000	—
Total long-term debt, net of unamortized discount and debt issuance costs	$1,234,733	$1,151,932

Senior Notes

2021 Convertible Notes. In September 2016, we issued $200 million of 1.125% convertible notes due September 15, 2021 (the "2021 Convertible Notes") in a public offering. Interest is payable in cash semiannually on each March 15 and September 15. The conversion price at maturity is $85.39 per share. 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, priced on the same day we issued the 2021 Convertible Notes. Approximately $4.8 million in costs associated with the issuance of the 2021 Convertible Notes were capitalized as debt issuance costs. As of September 30, 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.

Upon conversion, the 2021 Convertible Notes may be settled, at our sole election, in shares of our common stock, cash, or a combination of cash and shares of our common stock. 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 of our common stock, with cash paid in lieu of fractional shares.

2024 Senior Notes. In September 2016, we issued $400 million aggregate principal amount of 6.125% senior notes due September 15, 2024 (the “2024 Senior Notes”) in a private placement to qualified institutional buyers. In May 2017, in accordance with the registration rights agreement that we entered into with the initial purchasers when we issued the 2024 Senior Notes, we filed a registration statement with the SEC relating to an offer to exchange the 2024 Senior Notes for registered notes with substantially identical terms, and we completed the exchange offer in September 2017. The 2024 Senior Notes accrue interest from the date of issuance and interest is payable semi-annually on March 15 and September 15. Approximately $7.8 million in costs associated with the issuance of the 2024 Senior Notes were capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes using the effective interest method.

2026 Senior Notes. In November 2017, we issued $600 million aggregate principal amount of 5.75% senior notes due May 15, 2026, in a private placement to qualified institutional buyers. In June 2018, in accordance with the registration rights agreement that we entered into with the initial purchasers when we issued the 2024 Senior Notes, we filed a registration statement with the SEC relating to an offer to exchange the 2024 Senior Notes for registered notes with substantially identical terms, and we completed the exchange offer in July 2018. The 2026 Senior Notes accrue interest from the date of issuance and interest is payable semi-annually on May 15 and November 15. The first interest payment occurred on May 15, 2018. Approximately $7.6 million in costs associated with the issuance of the 2026 Senior Notes were capitalized as debt issuance costs and are being amortized as interest expense over the life of the notes using the effective interest method.

Our wholly-owned subsidiary PDC Permian, Inc. guarantees our obligations under the 2021 Convertible Notes, the 2026 Senior Notes and the 2024 Senior Notes (collectively, the "Notes"). Accordingly, condensed consolidating financial information for PDC and PDC Permian, Inc. is presented in the footnote titled Subsidiary Guarantor.

As of September 30, 2018, we were in compliance with all covenants related to the Notes.

Revolving Credit Facility

In May 2018, we entered into a Fourth Amended and Restated Credit Agreement (the “Restated Credit Agreement”) with certain banks and other lenders, including JPMorgan Chase Bank, N.A. as administrative agent. 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 from May 2020 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 JPMorgan Chase Bank, N.A.'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 September 30, 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 September 30, 2018, we were in compliance with all the revolving credit facility covenants.

As of September 30, 2018 and December 31, 2017, debt issuance costs related to our revolving credit facility were $8.6 million and $6.2 million, respectively, and are included in other assets on the condensed consolidated balance sheets. As of September 30, 2018, the weighted-average interest rate on the outstanding balance on our revolving credit facility, exclusive of fees on the unused commitment, was 4.2 percent.

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NOTE 10 - 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 vehicles under capital lease as of:

	September 30, 2018	December 31, 2017
	(in thousands)	
Vehicles	$7,255	$ 6,249
Accumulated depreciation	(2,931)	(1,882)
	$4,324	$ 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 September 30,	Amount (in thousands)
2019	$ 2,165
2020	2,427
2021	583
2022	138
2023	113
	5,426
Executory cost	(260)
Amount representing interest	(551)
Present value of minimum lease payments	$ 4,615
Short-term capital lease obligations	$ 1,897
Long-term capital lease obligations	2,718
	$ 4,615

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

NOTE 11 - INCOME TAXES

We evaluate and update our estimated annual effective income tax rate on a quarterly basis based on current and forecasted operating results and tax laws. Consequently, based upon the mix and timing of our actual annual earnings compared to annual projections, our effective tax rate may vary quarterly and may make quarterly comparisons not meaningful. The quarterly income tax provision is generally comprised of tax expense on income or benefit on loss at the most recent estimated annual effective income tax rate, adjusted for the effect of discrete items. The federal corporate statutory income tax rate decreased from 35 percent in 2017 to 21 percent in 2018 pursuant to the 2017 Tax Cuts and Jobs Act (the "2017 Tax Act").

The effective income tax rates for the three and nine months ended September 30, 2018 and 2017 are based upon a full year forecasted tax benefit on loss. The effective income tax rates differ from the statutory federal tax rate, primarily due to state taxes, stock-based compensation, nondeductible officers' compensation, nondeductible lobbying expenses, nondeductible penalties and federal tax credits. The effective income tax rate for the nine months ended September 30, 2018 includes discrete income tax provision items of $2.6 million relating to a valuation allowance placed on state tax credits offset by a $1.5 million benefit for additional deductions and credits claimed on the filed 2017 and 2016 federal and state tax returns. The net discrete tax expense from these discrete tax adjustments during the three and nine months ended September 30, 2018 resulted in a 12.3 percent and 0.5 percent decrease to our effective income tax rates, respectively. We anticipate the potential for increased periodic volatility in future effective tax rates from the impact of stock-based compensation tax deductions as they are treated as discrete tax items.

The effective income tax rates for the three and nine months ended September 30, 2018 were 53.0 percent and 23.3 percent benefit on loss, respectively, compared to 29.5 percent and 25.8 percent benefit on loss for the three and nine months ended September 30, 2017, respectively. The most significant elements related to the decrease in the effective income tax rate for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 is the noted reduction of the 2018 federal statutory rate to 21 percent and nondeductible impairment of goodwill during the nine months ended September 30, 2017.

As of September 30, 2018, there is no liability for unrecognized income tax benefits. As of the date of this report, we are current with our income tax filings in all applicable state jurisdictions and are not currently under any state income tax examinations. We continue to voluntarily participate in the Internal Revenue Service's ("IRS") Compliance Assurance Program for the 2017 and 2018 tax years. We have received final acceptance of our 2016 federal income tax return from the Joint Tax Committee.

NOTE 12 - ASSET RETIREMENT OBLIGATIONS

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

	Amount (in thousands)
Balance at December 31, 2017	$ 87,306
Obligations incurred with development activities	2,147

Obligations incurred with acquisition	4,326
Accretion expense	3,773
Revisions in estimated cash flows	754
Obligations discharged with asset retirements and divestiture	(9,593)
Balance at September 30, 2018	88,713
Current portion	(16,006)
Long-term portion	$ 72,707

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 condensed consolidated balance sheets.

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 condensed 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 and processing agreements for pipeline capacity:

	For the Twelve Months Ending September 30,						
Area	2019	2020	2021	2022	2023 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Wattenberg Field	19,142	30,850	31,025	31,025	98,717	210,759	April 30, 2026
Delaware Basin	48,387	41,426	25,075	5,326	—	120,214	December 31, 2021
Gas Marketing	7,117	7,136	7,117	6,228	—	27,598	August 31, 2022
Total	74,646	79,412	63,217	42,579	98,717	358,571	
Crude oil (MBbls)							
Wattenberg Field	7,888	7,302	5,475	5,475	3,180	29,320	April 30, 2023
Delaware Basin	6,651	8,833	8,214	8,030	10,054	41,782	December 31, 2023
Total	14,539	16,135	13,689	13,505	13,234	71,102	
Dollar commitment (in thousands)	$92,736	$87,056	$72,476	$71,457	$138,271	$461,996	

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. We currently expect that our future development plans will meet both the baseline and incremental volumes and we believe that the contractual target profit margin will be achieved with minimal payment from us, if any.

Delaware Basin. In May 2018, we entered into two firm sales agreements that are effective from June 1, 2018 through December 31, 2023 for an initial 11,400 barrels of crude oil per day and incrementally increasing to 26,400 barrels of crude oil per day with an integrated marketing company for our crude oil production in the Delaware Basin. 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 the three and nine months ended September 30, 2018, amounts related to long-term transportation volumes, net to our interest, for Wattenberg Field crude oil and Delaware Basin natural gas were $11.0 million and $16.2 million, respectively, and in accordance with the guidance in the New Revenue Standard, were netted against our crude oil and natural gas sales in our condensed consolidated statements of operations. In addition, for both the three and nine months ended September 30, 2018, $0.8 million related to long-term transportation volumes were recorded in transportation, gathering and processing expense in our condensed consolidated statements of operations. For the three and nine months ended September 30, 2017, amounts related to long-term transportation volumes for Wattenberg Field crude oil and Utica Shale natural gas were $2.6 million and $7.4 million, respectively, and were recorded in transportation, gathering and processing expense in our condensed 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, 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 for alleged breach of fiduciary duty. The lawsuit accuses PDC, as the managing general partner of the two partnerships, of, among other things, failing to maximize the productivity of the partnerships’ crude oil and natural gas wells. We filed a motion to dismiss the lawsuit on February 1, 2018, on the grounds that the complaint is deficient, including because the plaintiffs failed to allege that PDC refused a demand to take action on their claims. On March 14, 2018, the motion was denied as moot by the court because the plaintiffs requested leave to amend their complaint. In late April 2018, the plaintiffs filed an amendment to their complaint. Such amendment primarily alleges additional facts to support the plaintiffs’ claims and purports to add direct class action claims in addition to the original derivative claims. The amendment also adds three new individual defendants, all of whom are currently independent members of our Board of Directors. We moved to dismiss the claims against the individuals named as defendants and in response, the plaintiffs filed a second amended complaint on July 10, 2018. We filed a motion to dismiss this second amended complaint and the claims against the individuals named as defendants on July 31, 2018 and are awaiting a ruling at this time. We are currently unable to estimate any potential damages resulting from this lawsuit.

Partnership Bankruptcy Filings. On October 30, 2018, our two remaining affiliated partnerships (collectively, the "Partnerships") filed a petition under Chapter 11 of the Bankruptcy Code (the "Chapter 11 Proceedings") with 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"). 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. 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 September 30, 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 condensed 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 August 2015, we received a Clean Air Act Section 114 Information Request (the "Information Request") from the U.S. Environmental Protection Agency ("EPA"). The Information Request sought, among other things, information related to the design, operation and maintenance of our Wattenberg Field production facilities in the Denver-Julesburg Basin of Colorado ("DJ Basin"). The Information Request focused on historical operation and design information for 46 of our production facilities and requested sampling and analyses at the identified 46 facilities. We responded to the Information Request with the requested data in January 2016.

In addition, in December 2015, we received a Compliance Advisory pursuant to C.R.S. 25-7-115(2) from the Colorado Department of Public Health and Environment's (“CDPHE”) Air Quality Control Commission's Air Pollution Control Division alleging that we failed to design, operate and maintain certain condensate collection, storage, processing and handling operations to minimize leakage of volatile organic compounds at 65 facilities consistent with applicable standards under Colorado law.

In June 2017, 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 above referenced 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. 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. 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 this program. In the third quarter of 2018, we identified certain immaterial deficiencies in our implementation of the program. We have reported these immaterial deficiencies to the appropriate authorities and have remediated them. 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.

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. 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 September 30, 2018, there were 233,783 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Stock-based compensation expense	$5,578	$4,761	$16,357	$14,587
Income tax benefit	(1,337)	(1,781)	(3,921)	(5,457)
Net stock-based compensation expense	$4,241	$2,980	$12,436	$9,130

Stock Appreciation Rights

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. We had 7,962 SARs expire during the three months ended September 30, 2018. No SARs were awarded during the nine months ended September 30, 2018.

Total compensation cost related to non-vested SARs granted and not yet recognized in our condensed consolidated statement of operations as of September 30, 2018 was $0.9 million. The cost is expected to be recognized over a weighted-average period of 0.9 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 provided that a participant is continuously employed.

The following table presents the changes in non-vested time-based RSUs to all employees, including executive officers, for the nine months ended September 30, 2018:

	Shares	Weighted-Average Grant Date Fair Value per

		Share
Non-vested at December 31, 2017	472,132	$ 60.23
Granted	416,687	50.85
Vested	(219,768)	58.26
Forfeited	(36,137)	57.22
Non-vested at September 30, 2018	632,914	54.91

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

	Nine Months Ended September 30,	
	2018	2017
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$11,178	$13,266
Total intrinsic value of time-based awards non-vested	30,987	25,762
Market price per share as of September 30, 2018	48.96	49.03
Weighted-average grant date fair value per share	50.85	66.00

Total compensation cost related to non-vested time-based awards and not yet recognized in our condensed consolidated statements of operations as of September 30, 2018 was $24.5 million. This cost is expected to be recognized over a weighted-average period of 1.9 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.

The Compensation Committee awarded a total of 90,778 market-based PSUs to our executive officers during the nine months ended September 30, 2018. 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:

	Nine Months Ended September 30,	
	2018	2017
Expected term of award (in years)	3	3
Risk-free interest rate	2.4 %	1.4 %
Expected volatility	42.3%	51.4%

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 the nine months ended September 30, 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
Forfeited	(4,128)	94.02
Non-vested at September 30, 2018	138,999	74.57

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

	Nine Months Ended September 30,	
	2018	2017
	(in thousands, except per share data)	
Total intrinsic value of market-based awards non-vested	$6,805	$3,750
Market price per common share as of September 30,	48.96	49.03
Weighted-average grant date fair value per share	69.98	94.02

Total compensation cost related to non-vested market-based awards not yet recognized in our condensed consolidated statements of operations as of September 30, 2018 was $6.1 million. This cost is expected to be recognized over a weighted-average period of 1.7 years.

Preferred Stock

We are authorized to issue 50,000,000 shares of preferred stock, par value $0.01 per share, which may be issued in one or more series, with such rights, preferences, privileges and restrictions as shall be fixed by our Board of Directors from time to time. Through September 30, 2018, no shares of preferred stock have been issued.

NOTE 15 - 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, 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Weighted-average common shares outstanding - basic	66,073	65,865	66,032	65,825
Weighted-average common shares and equivalents outstanding - diluted	66,073	65,865	66,032	65,825

We reported a net loss for the three and nine months ended September 30, 2018 and 2017. As a result, our basic and diluted weighted-average common shares outstanding were the same for that period 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
RSU and PSU	719	588	655	585
Other equity-based awards	314	48	319	82
Total anti-dilutive common share equivalents	1,033	636	974	667

In September 2016, we issued the 2021 Convertible Notes, which give the holders, at our election, 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 could be included in the diluted earnings per share calculation using the treasury stock method if the average market share price exceeds the $85.39 conversion price during the periods presented. During the three and nine months ended September 30, 2018 and 2017, the average market price of our common stock did not exceed the conversion price; therefore, shares issuable upon conversion of the 2021 Convertible Notes were not included in the diluted earnings per share calculation.

NOTE 16 - SUBSIDIARY GUARANTOR

PDC Permian, Inc., our wholly-owned subsidiary, guarantees our obligations under our publicly-registered senior notes. The following presents the condensed 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 is 100 percent owned by the Parent. 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 condensed consolidating financial information follows the same accounting policies as described in the notes to the condensed consolidated financial statements.

The following condensed consolidating financial statements have been prepared on the same basis of accounting as our condensed 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.

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PDC ENERGY, INC.
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(unaudited)

	Condensed Consolidating Balance Sheets September 30, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Current assets:				
Cash and cash equivalents	$1,369	$—	$—	$1,369
Accounts receivable, net	186,274	54,881	—	241,155
Fair value of derivatives	7,555	—	—	7,555
Prepaid expenses and other current assets	5,983	730	—	6,713
Total current assets	201,181	55,611	—	256,792
Properties and equipment, net	2,216,649	2,092,372	—	4,309,021
Intercompany receivable	404,641	—	(404,641)	—
Investment in subsidiaries	1,504,791	—	(1,504,791)	—
Fair value of derivatives	3,949	—	—	3,949
Other assets	26,327	5,135	—	31,462
Total Assets	$4,357,538	$2,153,118	$(1,909,432)	$4,601,224
Liabilities and Stockholders' Equity				
Liabilities				
Current liabilities:				
Accounts payable	$135,264	$115,817	$—	$251,081
Production tax liability	53,573	5,966	—	59,539
Fair value of derivatives	205,013	—	—	205,013
Funds held for distribution	86,173	18,086	—	104,259
Accrued interest payable	15,419	6	—	15,425
Other accrued expenses	38,366	894	—	39,260
Total current liabilities	533,808	140,769	—	674,577
Intercompany payable	—	404,641	(404,641)	—
Long-term debt	1,234,733	—	—	1,234,733
Deferred income taxes	44,066	94,897	—	138,963
Asset retirement obligations	65,248	7,459	—	72,707
Fair value of derivatives	61,013	—	—	61,013
Other liabilities	76,426	561	—	76,987
Total liabilities	2,015,294	648,327	(404,641)	2,258,980
Commitments and contingent liabilities				
Stockholders' Equity				
Common shares	661	—	—	661
Additional paid-in capital	2,514,861	1,766,775	(1,766,775)	2,514,861
Retained earnings	(170,126)	(261,984)	261,984	(170,126)
Treasury shares	(3,152)	—	—	(3,152)
Total stockholders' equity	2,342,244	1,504,791	(1,504,791)	2,342,244

Total Liabilities and Stockholders' Equity	$4,357,538	$2,153,118	$(1,909,432)	$4,601,224

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(unaudited)

	Condensed Consolidating Balance Sheets			
	December 31, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
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, net	40,084	—	—	40,084
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	$4,205,548	$2,082,159	$(1,867,816)	$4,419,891
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
Fair value of derivatives	22,343	—	—	22,343
Other liabilities	57,009	324	—	57,333
Total liabilities	1,697,899	464,622	(250,279)	1,912,242
Commitments and contingent liabilities				
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	$4,205,548	$2,082,159	$(1,867,816)	$4,419,891

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(unaudited)

	Condensed Consolidating Statements of Operations Three Months Ended September 30, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$ 280,866	$ 91,573	$ —	$ 372,439
Commodity price risk management loss, net	(94,394)	—	—	(94,394)
Other income	2,300	372	—	2,672
Total revenues	188,772	91,945	—	280,717
Costs, expenses and other				
Lease operating expenses	23,219	9,827	—	33,046
Production taxes	17,852	6,132	—	23,984
Transportation, gathering and processing expenses	4,520	4,714	—	9,234
Exploration, geologic and geophysical expense	279	753	—	1,032
Impairment of properties and equipment	98	1,390	—	1,488
General and administrative expense	43,886	4,354	—	48,240
Depreciation, depletion and amortization	97,370	50,170	—	147,540
Accretion of asset retirement obligations	1,084	116	—	1,200
(Gain) loss on sale of properties and equipment	(141)	2,259	—	2,118
Other expenses	2,711	—	—	2,711
Total costs, expenses and other	190,878	79,715	—	270,593
Income (loss) from operations	(2,106)	12,230	—	10,124
Interest expense	(18,232)	610	—	(17,622)
Interest income	188	—	—	188
Income (loss) before income taxes	(20,150)	12,840	—	(7,310)
Income tax (expense) benefit	5,753	(1,877)	—	3,876
Equity in income of subsidiary	10,963	—	(10,963)	—
Net income (loss)	$ (3,434)	$ 10,963	$ (10,963)	$ (3,434)

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(unaudited)

	Condensed Consolidating Statements of Operations Three Months Ended September 30, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$199,565	$33,168	$ —	$ 232,733
Commodity price risk management loss, net	(52,178)	—	—	(52,178)
Other income	2,628	52	—	2,680
Total revenues	150,015	33,220	—	183,235
Costs, expenses and other				
Lease operating expenses	18,181	7,172	—	25,353
Production taxes	13,467	2,049	—	15,516
Transportation, gathering and processing expenses	5,970	3,824	—	9,794
Exploration, geologic and geophysical expense	216	41,692	—	41,908
Impairment of properties and equipment	1,148	251,592	—	252,740
Impairment of goodwill	—	75,121	—	75,121
General and administrative expense	26,207	3,092	—	29,299
Depreciation, depletion and amortization	106,623	18,615	—	125,238
Accretion of asset retirement obligations	1,386	86	—	1,472
Gain on sale of properties and equipment	(62)	—	—	(62)
Other expenses	2,947	—	—	2,947
Total costs, expenses and other	176,083	403,243	—	579,326
Loss from operations	(26,068)	(370,023)	—	(396,091)
Interest expense	(19,647)	372	—	(19,275)
Interest income	479	—	—	479
Loss before income taxes	(45,236)	(369,651)	—	(414,887)
Income tax benefit	30,274	92,076	—	122,350
Equity in loss of subsidiary	(277,575)	—	277,575	—
Net loss	$(292,537)	$(277,575)	$ 277,575	$ (292,537)

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	Condensed Consolidating Statements of Operations Nine Months Ended September 30, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$757,263	$246,334	$ —	$1,003,597
Commodity price risk management loss, net	(257,760)	—	—	(257,760)
Other income	7,295	716	—	8,011
Total revenues	506,798	247,050	—	753,848
Costs, expenses and other				
Lease operating expenses	68,013	26,929	—	94,942
Production taxes	50,122	16,635	—	66,757
Transportation, gathering and processing expenses	11,361	14,150	—	25,511
Exploration, geologic and geophysical expense	887	3,666	—	4,553
Impairment of properties and equipment	191	194,039	—	194,230
General and administrative expense	108,597	12,586	—	121,183
Depreciation, depletion and amortization	284,963	124,989	—	409,952
Accretion of asset retirement obligations	3,460	313	—	3,773
Loss on sale of properties and equipment	940	2,259	—	3,199
Other expenses	8,187	—	—	8,187
Total costs, expenses and other	536,721	395,566	—	932,287
Loss from operations	(29,923)	(148,516)	—	(178,439)
Interest expense	(54,244)	1,683	—	(52,561)
Interest income	405	—	—	405
Loss before income taxes	(83,762)	(146,833)	—	(230,595)
Income tax benefit	19,678	34,087	—	53,765
Equity in loss of subsidiary	(112,746)	—	112,746	—
Net loss	$(176,830)	$(112,746)	$ 112,746	$(176,830)

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	Condensed Consolidating Statements of Operations Nine Months Ended September 30, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$561,132	$74,895	$ —	$ 636,027
Commodity price risk management gain, net	86,458	—	—	86,458
Other income	9,512	103	—	9,615
Total revenues	657,102	74,998	—	732,100
Costs, expenses and other				
Lease operating expenses	49,555	15,615	—	65,170
Production taxes	38,000	4,957	—	42,957
Transportation, gathering and processing expenses	16,953	5,231	—	22,184
Exploration, geologic and geophysical expense	744	43,151	—	43,895
Impairment of properties and equipment	2,282	280,217	—	282,499
Impairment of goodwill	—	75,121	—	75,121
General and administrative expense	76,353	8,792	—	85,145
Depreciation, depletion and amortization	317,088	43,479	—	360,567
Accretion of asset retirement obligations	4,660	246	—	4,906
Gain on sale of properties and equipment	(754)	—	—	(754)
Provision for uncollectible notes receivable	(40,203)	—	—	(40,203)
Other expenses	10,365	—	—	10,365
Total costs, expenses and other	475,043	476,809	—	951,852
Income (loss) from operations	182,059	(401,811)	—	(219,752)
Interest expense	(59,044)	685	—	(58,359)
Interest income	1,487	—	—	1,487
Income (loss) before income taxes	124,502	(401,126)	—	(276,624)
Income tax (expense) benefit	(32,174)	103,657	—	71,483
Equity in loss of subsidiary	(297,469)	—	297,469	—
Net loss	$(205,141)	$(297,469)	$ 297,469	$ (205,141)

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PDC ENERGY, INC.
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	Condensed Consolidating Statements of Cash Flows			
	Nine Months Ended September 30, 2018			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$405,326	$172,508	$ —	$ 577,834
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural gas properties	(360,457)	(325,092)	—	(685,549)
Capital expenditures for other properties and equipment	(2,834)	(905)	—	(3,739)
Acquisition of crude oil and natural gas properties, including settlement adjustments	(181,501)	(71)	—	(181,572)
Proceeds from sale of properties and equipment	1,918	525	—	2,443
Proceeds from divestiture	43,493	—	—	43,493
Restricted cash	1,249	—	—	1,249
Intercompany transfers	(153,121)	—	153,121	—
Net cash from investing activities	(651,253)	(325,543)	153,121	(823,675)
Cash flows from financing activities:				
Proceeds from revolving credit facility	629,000	—	—	629,000
Repayment of revolving credit facility	(554,000)	—	—	(554,000)
Payment of debt issuance costs	(4,086)	—	—	(4,086)
Purchases of treasury shares	(4,700)	—	—	(4,700)
Other	(842)	(86)	—	(928)
Intercompany transfers	—	153,121	(153,121)	—
Net cash from financing activities	65,372	153,035	(153,121)	65,286
Net change in cash, cash equivalents and restricted cash	(180,555)	—	—	(180,555)
Cash, cash equivalents and restricted cash, beginning of period	189,925	—	—	189,925
Cash, cash equivalents and restricted cash, end of period	$9,370	$—	$ —	$ 9,370

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	Condensed Consolidating Statements of Cash Flows			
	Nine Months Ended September 30, 2017			
	Parent	Guarantor	Eliminations	Consolidated
	(in thousands)			
Cash flows from operating activities	$391,965	$28,687	$ —	$420,652
Cash flows from investing activities:				
Capital expenditures for development of crude oil and natural gas properties	(315,718)	(213,132)	—	(528,850)
Capital expenditures for other properties and equipment	(2,488)	(1,252)	—	(3,740)
Acquisition of crude oil and natural gas properties, including settlement adjustments	(19,761)	5,279	—	(14,482)
Proceeds from sale of properties and equipment	3,322	—	—	3,322
Sale of promissory note	40,203	—	—	40,203
Restricted cash	(9,250)	—	—	(9,250)
Sale of short-term investments	49,890	—	—	49,890
Purchase of short-term investments	(49,890)	—	—	(49,890)
Intercompany transfers	(189,239)	—	189,239	—
Net cash from investing activities	(492,931)	(209,105)	189,239	(512,797)
Cash flows from financing activities:				
Purchases of treasury shares	(5,325)	—	—	(5,325)
Other	(906)	(45)	—	(951)
Intercompany transfers	—	189,239	(189,239)	—
Net cash from financing activities	(6,231)	189,194	(189,239)	(6,276)
Net change in cash, cash equivalents and restricted cash	(107,197)	8,776	—	(98,421)
Cash, cash equivalents and restricted cash, beginning of period	240,487	3,613	—	244,100
Cash, cash equivalents and restricted cash, end of period	$133,290	$12,389	$ —	$145,679

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis, as well as other sections in this report, should be read in conjunction with our condensed consolidated financial statements and related notes included elsewhere in this report. Further, we encourage you to review the Special Note Regarding Forward-Looking Statements.

EXECUTIVE SUMMARY

Production and Financial Overview

Production volumes increased to 10.1 MMboe and 28.4 MMboe for the three and nine months ended September 30, 2018, respectively, representing increases of 19 percent and 23 percent as compared to the three and nine months ended September 30, 2017, respectively. Crude oil production increased 25 percent and 31 percent for the three and nine months ended September 30, 2018, respectively, compared to the three and nine months ended September 30, 2017. Crude oil production comprised approximately 42 percent and 40 percent of total production for the nine months ended September 30, 2018 and 2017, respectively. NGLs production increased 15 percent for each of the three and nine months ended September 30, 2018 compared to the three and nine months ended September 30, 2017. Natural gas production increased 14 percent and 18 percent for the three and nine months ended September 30, 2018, respectively, compared to the three and nine months ended September 30, 2017. For the month ended September 30, 2018, we maintained an average daily production rate of approximately 121,000 Boe per day, up from approximately 95,000 Boe per day for the month ended September 30, 2017.

On a sequential quarterly basis, total production and crude oil production volumes for the three months ended September 30, 2018 as compared to the three months ended June 30, 2018 increased by eight percent and nine percent, respectively. In the Wattenberg Field, elevated line pressures throughout 2018, which have been greater than anticipated despite the start-up of a new plant as discussed below, and unplanned gathering system facility downtime hampered our production growth from all of our wells during the three and nine months ended September 30, 2018. These operating challenges are reflected in our expected full year 2018 production outlook as discussed under 2018 Operational and Financial Outlook. In response to significant production growth in the Wattenberg Field, our primary third-party midstream provider turned a new processing facility on line in August 2018. We did not experience the full benefit of the facility during the three months ended September 30, 2018 as it was being integrated into the midstream provider’s overall gathering system. However, we did see sequential monthly improvement in Wattenberg Field production during the quarter.

Crude oil, natural gas and NGLs sales revenue increased to $372.4 million and $1.0 billion for the three and nine months ended September 30, 2018, respectively, compared to $232.7 million and $636.0 million for the three and nine months ended September 30, 2017, respectively. The 60 percent and 58 percent increases in sales revenues were driven by the 19 percent and 23 percent increases in production and the 35 percent and 29 percent increases in average realized commodity prices for the three and nine months ended September 30, 2018, as compared to the respective periods in 2017. The adoption of the New Revenue Standard in January 2018 did not significantly impact the change in our crude oil, natural gas and NGLs sales revenue for the three and nine months ended September 30, 2018, as compared to the respective periods in 2017. See the footnote titled Revenue Recognition to our condensed consolidated financial statements included elsewhere in this report for additional information regarding the New Revenue Standard.

We had negative net settlements from our commodity derivative contracts of $48.1 million and $90.5 million for the three and nine months ended September 30, 2018, respectively, as compared to positive net settlements of $9.6 million and $22.2 million for the three and nine months ended September 30, 2017, 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 34 percent to $324.3 million for the three months ended September 30, 2018 from $242.3 million for the three months ended September 30, 2017 and increased 39 percent to $913.1 million for the nine months ended September 30, 2018 from $658.2 million for the nine months ended September 30, 2017.

For the three and nine months ended September 30, 2018, we generated net losses of $3.4 million and $176.8 million, respectively, or $0.05 and $2.68 per diluted share, compared to net losses of $292.5 million and $205.1 million, respectively, or $4.44 and $3.12 per diluted share for the comparable periods in 2017. Our net loss for the three months ended September 30, 2018 was most negatively impacted by the commodity price risk management loss, partially offset by the increase in crude oil, natural gas and NGLs sales. Our net loss for the nine months ended September 30, 2018 was most negatively impacted by the commodity price risk management loss, Delaware Basin leasehold impairments and increases in our operating costs, partially offset by the increase in crude oil, natural gas and NGLs sales.

During the three and nine months ended September 30, 2018, our adjusted EBITDAX, a non-U.S. GAAP financial measure, was $213.2 million and $617.9 million, respectively, compared to $166.9 million and $497.6 million for the comparable periods in 2017. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of these non-U.S. GAAP financial measures and a reconciliation of these measures to the most comparable U.S. GAAP measures. The 28 percent increase in our adjusted EBITDAX for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017 was primarily due to the increase in crude oil, natural gas and NGLs sales of $139.7 million. The increase was partially offset by an increase in operating costs of $34.5 million and a decrease in commodity derivative settlements of $57.7 million. The 24 percent increase in our adjusted EBITDAX for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 was primarily due to the increase in crude oil, natural gas and NGLs sales of $367.6 million. This increase was partially offset by an increase in operating costs of $92.9 million, a decrease in commodity derivative settlements of $112.7 million and the reversal of a provision for uncollectible notes receivable of $40.2 million in the nine months ended September 30, 2017.

Our cash flows from operations were $577.8 million and our adjusted cash flows from operations, a non-U.S. GAAP financial measure, were $575.3 million for the nine months ended September 30, 2018.

Liquidity

Available liquidity as of September 30, 2018 was $626.4 million, which was comprised of $1.4 million of cash and cash equivalents and $625.0 million available for borrowing under our revolving credit facility at our then-current commitment level. In October 2018, we increased the commitment level on our revolving credit facility to the current borrowing base amount of $1.3 billion. Assuming a commitment level of $1.3 billion on our revolving credit facility at September 30, 2018, our total liquidity position would have been approximately $1.23 billion. Based on our current production forecast for the remainder of 2018 and assuming current NYMEX market prices for the remainder of the year for crude oil and natural gas, less anticipated differentials, we expect our 2018 capital investments in crude oil and natural gas properties, excluding acquisitions and corporate capital, to exceed our 2018 cash flows from operations by $125 million to $150 million, of which approximately $65 million was financed by an amendment to a midstream oil dedication agreement that occurred in January 2018 and the divestiture of our Utica Shale properties that occurred in March 2018. The increase in the anticipated outspend can primarily be attributed to the impact on our production of continued elevated line pressures in the Wattenberg Field. We experienced the outspend during the first nine months of 2018 and expect cash flows from operations to exceed capital investment during the remainder of the year. As a result, we expect to be minimally drawn on our credit facility at December 31, 2018, subject to potential borrowings to satisfy short-term working capital needs.

We use our available liquidity for working capital requirements, capital investments, acquisitions, support for letters of credit and for general corporate purposes. 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 and Divestitures

Bayswater Asset Acquisition. In January 2018, we closed the Bayswater Asset Acquisition for approximately $200.0 million. See the footnote titled Business Combination to our condensed consolidated financial statements included elsewhere in this report for further details.

Utica Shale Divestiture. In March 2018, we completed the Utica Shale Divestiture for net cash proceeds of approximately $39 million. The divestiture of these assets has not had a material impact on our results of operations or reserves. See the footnote titled Properties and Equipment to our condensed consolidated financial statements included elsewhere in this report for further details.

Acreage Exchange. In July 2018, we entered into an acreage exchange transaction that involved the consolidation of certain acreage positions in the core area of the Wattenberg Field. Upon closing, we received approximately 2,500 net acres and $3.7 million in cash in exchange for approximately 2,600 acres. The difference in the number of net acres was primarily due to variances in working and net revenue interests.

Operational Overview

During the nine months ended September 30, 2018, we continued to execute our strategic plan to grow production while preserving our financial strength and liquidity. During the three months ended September 30, 2018, we ran three drilling rigs in each of the Wattenberg Field and the Delaware Basin and we expect to maintain a three rig pace in both the Wattenberg Field and the Delaware Basin during the remainder of 2018.

The following tables summarizes our drilling and completion activity for the nine months ended September 30, 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	121	112.0	22	20.2	143	132.2
Acquired in-process (1)	24	18.2	—	—	24	18.2
Wells turned-in-line	(99)	(92.6)	(22)	(20.1)	(121)	(112.7)
In-process as of September 30, 2018	133	117.7	13	12.3	146	130.0

	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	28	3.6	5	0.3	33	3.9
Acquired DUCs (operated at September 30, 2018) (1)	(3)	(1.5)	—	—	(3)	(1.5)
Wells turned-in-line	(29)	(3.2)	(11)	(1.2)	(40)	(4.4)
In-process as of September 30, 2018	10	1.5	2	0.1	12	1.6

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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 three to nine months of drilling.

2018 Operational and Financial Outlook

Our previously announced production guidance range for 2018 was 40 MMBoe to 42 MMBoe, or approximately 110,000 Boe per day to 115,000 Boe per day. Although we have seen some improvement in the line pressures of our primary third-party midstream provider’s gathering system in the Wattenberg Field during the three months ended September 30, 2018, the new facilities continue to be integrated into the midstream provider’s overall gathering system and line pressure has continued to be elevated. Ongoing optimization of the gathering system and unplanned gathering system facility downtime continued to constrain production in the Wattenberg Field throughout the third quarter beyond what we had initially modeled. Primarily as a result of these gathering system constraints, we currently expect that our full year 2018 production will be at the low end of the production guidance range, or approximately 40 MMBoe. We expect that approximately 42 to 45 percent of our 2018 production will be crude oil and approximately 19 to 22 percent will be NGLs, for total liquids of approximately 61 to 67 percent. We expect our 2018 capital investment in crude oil and natural gas properties, excluding acquisitions and corporate capital, to be between $950 million and $985 million.

We believe that we maintain significant operational flexibility to control the pace of our capital spending. As we execute our capital investment program, we continually monitor, among other things, commodity prices, development costs, midstream capacity and offset and continuous drilling obligations. While we have experienced some service cost increases in the first nine months of 2018, drilling efficiencies have partially offset the impact of these increases. Should commodity pricing or the operating environment deteriorate, we may determine that an adjustment to our development plan is appropriate. We believe we have ample opportunities to reduce capital spending if necessary in order to stay within our capital investment plan, including, but not limited to, reducing the number of rigs being utilized in our drilling program and/or managing our completion schedule. This flexibility is more limited in the Delaware Basin given leasehold maintenance requirements.

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Wattenberg Field. We are drilling in the Niobrara and Codell plays within the field and anticipate spudding approximately 150 to 165 wells and turning-in-line approximately 145 to 160 operated wells in 2018. Our 2018 capital investment program is estimated to be approximately $520 million to $535 million in the Wattenberg Field, with over 90 percent anticipated to be invested in operated drilling and completion activity. The remainder of the Wattenberg Field capital investment program is expected to be used for non-operated wells and miscellaneous workover and capital projects.

Delaware Basin. Total capital investment in the Delaware Basin in 2018 is estimated to be approximately $430 million to $450 million, of which approximately 80 percent is allocated to the spudding and turning-in-line of approximately 25 to 30 operated wells, primarily targeting the Wolfcamp formation. Based on the timing of our operations and requirements to meet our drilling obligations, we may adapt our capital investment program 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 invest approximately five percent of our capital for leasing, non-operated capital, seismic and technical studies, with an additional approximately 15 percent for midstream-related projects, including oil and gas gathering systems and water supply and disposal systems. In addition, we are in the process of evaluating our strategic alternatives with respect to our midstream assets in the Delaware Basin.

Financial Guidance.

The following table sets forth our previously announced financial guidance for the year ended December 31, 2018 for certain expenses and price differentials:

	Low	High
Operating Expenses		
Lease operating expenses ($/Boe)	$3.00	$3.15
Transportation, gathering and processing expenses ("TGP") ($/Boe)	$0.80	$0.90
Production taxes (% of crude oil, natural gas and NGLs sales)	6 %	8 %
General and administrative expense ($/Boe) (1)	$3.40	$3.70
Estimated Price Realizations (% of NYMEX, excludes TGP)		
Crude oil	91%	95%
Natural gas	55%	60%
NGLs	30%	35%

(1) Excludes $8.0 million of general and administrative expense related to legal costs.

We currently expect that our full year 2018 per Boe metrics shown above will be at or slightly exceed the high end of the guidance ranges provided, primarily as a result of gathering system constraints impacting our anticipated production in the Wattenberg Field, which would likely result in production being at the low end of the production guidance range, or approximately 40 MMboe.

Regulatory Update

Statutory Ballot Initiative. Certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have sponsored an initiative, now known as Proposition 112, that will be voted on in November 2018. If approved, Proposition 112 would result in future oil and natural gas development in the state being essentially eliminated over time. The proposal would take effect by the end of 2018.

The proposition would require all new oil and gas development facilities to be located at least 2,500 feet away from any occupied structure or “vulnerable areas,” broadly defined to include playgrounds, permanent sports fields, amphitheaters, public parks, public open space, public and community drinking water sources, irrigation canals, reservoirs, lakes, rivers, perennial or intermittent streams and creeks and any additional vulnerable areas designated by the state or a local government. The state or local government may require that new oil and gas development be located a larger distance away from an occupied structure or vulnerable areas than required by Proposition 112. The current minimum required setback between oil and gas development facilities and occupied structures is generally 500 feet and 1,000 feet from high-occupancy structures such as schools or apartment buildings. Federal lands would be excluded from the effect of Proposition 112. The Colorado Oil and Gas Conservation Commission has estimated that implementation of the proposition would make drilling unlawful on approximately 85 percent of the non-federal surface lands of the state of Colorado, and approximately 85 percent of the non-federal lands of Weld County.

Although numerous aspects of Proposition 112 are unclear and subject to legal and regulatory interpretation, we believe that if it passes, we would be allowed to drill wells for which we have secured drilling permits as of the date the new statute takes effect. We currently expect that we will have drilling permits for approximately 200 wells in the Wattenberg Field by year-end 2018, and would expect to drill all or substantially all of the permitted locations prior to the expiration of those permits, which is generally two years after the date granted. We also anticipate having approximately 100 DUCs in the field by year-end 2018, and believe we would be able to complete those wells within the permitted time period. We would also expect to work with industry peers on rulemaking or legislative processes that could mitigate the impact of the new setback requirements to the extent possible and to pursue any available legal remedies.

If passed, Proposition 112 would effectively prohibit the vast majority of our planned future drilling activities in Colorado after the drilling of currently permitted wells, and would therefore make it impossible to continue to pursue our current development plans. As a result, we would expect it to have a material adverse effect on our reserves and inventory for the Wattenberg Field as of year-end 2018. However, due to our expected number of permitted wells and DUCs at year-end 2018, we do not believe that the implementation of Proposition 112 would have a material adverse effect on our 2019 development plans and expected production growth in 2019. The passing of Proposition 112 could potentially have a modest impact on our borrowing base under our revolving credit facility in early 2019. After 2019, Proposition 112 would have increasingly adverse effects on our future operational and financial results and may also impact the development plans of third-party midstream providers. See Item 1A. Risk Factors - If approved by voters, Proposition 112 would impose severe limits on the number of permissible drilling locations in the Wattenberg Field, thereby adversely affecting our future growth and numerous other aspects of our business, for additional information regarding the potential impacts of the passing of Proposition 112.

Ozone Classification. In 2016, the EPA increased the state of Colorado’s non-attainment ozone classification for the Denver Metro North Front Range Ozone Eight-Hour Non-Attainment ("Denver Metro/North Front Range NAA") area from “marginal” to “moderate” under the 2008 national ambient air quality standard (“NAAQS”). This increase in non-attainment status triggered significant additional obligations for the state under the Clean Air Act ("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 the first nine months of 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.

2018 Colorado General Election. A general election will be held in November 2018, with high-profile races on the federal, state and local levels. Newly-elected officials may take a different approach than their predecessors to regulatory and legislative issues affecting the oil and gas industry. Because a substantial portion of our current operations and reserves are located in Colorado, the risks we face with respect to the outcome of the November 2018 Colorado political elections are greater than those of our competitors with more geographically diverse operations. We cannot predict the outcome of the election.

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Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Percentage Change	2018	2017	Percentage Change
	(dollars in millions, except per unit data)					
Production						
Crude oil (MBbls)	4,296	3,439	24.9 %	12,040	9,184	31.1 %
Natural gas (MMcf)	21,765	19,070	14.1 %	62,040	52,437	18.3 %
NGLs (MBbls)	2,177	1,892	15.1 %	6,010	5,249	14.5 %
Crude oil equivalent (MBoe)	10,100	8,509	18.7 %	28,390	23,172	22.5 %
Average Boe per day (Boe)	109,783	92,491	18.7 %	103,993	84,880	22.5 %
Crude Oil, Natural Gas and NGLs Sales						
Crude oil	$284.7	$157.0	81.3 %	$763.7	$428.8	78.1 %
Natural gas	34.7	41.5	(16.4)%	103.4	116.7	(11.4)%
NGLs	53.0	34.2	55.0 %	136.5	90.5	50.8 %
Total crude oil, natural gas and NGLs sales	$372.4	$232.7	60.0 %	$1,003.6	$636.0	57.8 %
Net Settlements on Commodity Derivatives						
Crude oil	$(51.6)	$5.4	*	$(104.1)	$7.4	*
Natural gas	4.8	6.3	(23.8)%	18.7	16.8	11.3 %
NGLs (propane portion)	(1.3)	(2.1)	(38.1)%	(5.1)	(2.0)	155.0 %
Total net settlements on derivatives	$(48.1)	$9.6	*	$(90.5)	$22.2	*
Average Sales Price (excluding net settlements on derivatives)						
Crude oil (per Bbl)	$66.27	$45.66	45.1 %	$63.43	$46.69	35.9 %
Natural gas (per Mcf)	1.60	2.17	(26.3)%	1.67	2.23	(25.1)%
NGLs (per Bbl)	24.35	18.11	34.5 %	22.71	17.24	31.7 %
Crude oil equivalent (per Boe)	36.88	27.35	34.9 %	35.35	27.45	28.8 %
Average Costs and Expenses (per Boe)						
Lease operating expenses	$3.27	$2.98	9.7 %	$3.34	$2.81	18.9 %
Production taxes	2.37	1.82	30.2 %	2.35	1.85	27.0 %
Transportation, gathering and processing expenses	0.91	1.15	(20.9)%	0.90	0.96	(6.3)%
General and administrative expense	4.78	3.44	39.0 %	4.27	3.67	16.3 %
Depreciation, depletion and amortization	14.61	14.72	(0.7)%	14.44	15.56	(7.2)%
Lease Operating Expenses by Operating Region (per Boe)						
Wattenberg Field	$3.01	$2.49	20.9 %	$3.11	$2.45	26.9 %
Delaware Basin	4.09	6.07	(32.6)%	4.13	5.76	(28.3)%
Utica Shale (1)	—	1.91	(100.0)%	3.46	1.60	116.3 %

* Percentage change is not

meaningful. Amounts may not recalculate due to rounding.

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

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Crude Oil, Natural Gas and NGLs Sales

For the three and nine months ended September 30, 2018, crude oil, natural gas and NGLs sales revenue increased compared to the three and nine months ended September 30, 2017 due to the following (in millions):

	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
	(in millions)	
Increase in production	$50.1	$ 167.9
Increase in average crude oil price	88.6	201.5
Decrease in average natural gas price	(12.6)	(34.7)
Increase in average NGLs price	13.6	32.9
Total increase in crude oil, natural gas and NGLs sales revenue	$139.7	$ 367.6

Crude Oil, Natural Gas and NGLs Production

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

Production by Operating Region	Three Months Ended September 30, 2018	2017	Percentage Change	Nine Months Ended September 30, 2018	2017	Percentage Change
Crude oil (MBbls)						
Wattenberg Field	3,254	2,943	10.6 %	9,076	7,883	15.1 %
Delaware Basin	1,042	436	139.0 %	2,918	1,075	171.4 %
Utica Shale (1)	—	60	(100.0)%	46	226	(79.6)%
Total	4,296	3,439	24.9 %	12,040	9,184	31.1 %
Natural gas (MMcf)						
Wattenberg Field	16,808	15,788	6.5 %	48,169	44,694	7.8 %
Delaware Basin	4,957	2,781	78.2 %	13,457	6,052	122.4 %
Utica Shale (1)	—	501	(100.0)%	414	1,691	(75.5)%
Total	21,765	19,070	14.1 %	62,040	52,437	18.3 %
NGLs (MBbls)						
Wattenberg Field	1,643	1,564	5.1 %	4,616	4,473	3.2 %
Delaware Basin	534	282	89.4 %	1,360	625	117.6 %
Utica Shale (1)	—	46	(100.0)%	34	151	(77.5)%
Total	2,177	1,892	15.1 %	6,010	5,249	14.5 %
Crude oil equivalent (MBoe)						
Wattenberg Field	7,698	7,138	7.8 %	21,721	19,805	9.7 %
Delaware Basin	2,402	1,182	103.2 %	6,520	2,709	140.7 %
Utica Shale (1)	—	189	(100.0)%	149	658	(77.4)%
Total	10,100	8,509	18.7 %	28,390	23,172	22.5 %
Average crude oil equivalent per day (Boe)						
Wattenberg Field	83,674	77,582	7.9 %	79,564	72,545	9.7 %
Delaware Basin	26,109	12,845	103.3 %	23,883	9,923	140.7 %

Utica Shale (1)	—	2,064	(100.0)%	546	2,412	(77.4)%
Total	109,783	92,491	18.7 %	103,993	84,880	22.5 %

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:

Three Months Ended September 30, 2018

	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	43%	36%	21%	100%
Delaware Basin	44%	34%	22%	100%

Three Months Ended September 30, 2017

	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	41%	37%	22%	100%
Delaware Basin	37%	39%	24%	100%

Nine Months Ended September 30, 2018

	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	42%	37%	21%	100%
Delaware Basin	45%	34%	21%	100%

Nine Months Ended September 30, 2017

	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	39%	38%	23%	100%
Delaware Basin	40%	37%	23%	100%

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, the Wattenberg Field and the Delaware Basin, 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 July 2017 and continuing through the nine months ended September 30, 2018. The elevated pressures were primarily due to continued increases in field-wide production volumes, which filled to capacity the gathering system operated by DCP Midstream, LP (“DCP”), our primary midstream service provider in the field. Additional system constraints were caused by gathering line freezes that occur more often at high line pressures, especially during cold weather, as well as unexpected facility downtime.
In 2017, we and other operators entered into agreements with DCP relating to the construction of two additional processing plants. The agreements impose baseline volume commitments on us and the other operators and guarantee a specified profit margin to DCP for a three-year period beginning on the initial start-up date of each plant. Under our current drilling plans and in the current commodity pricing environment, we expect to satisfy the volume commitment and profit margin requirements with minimal or no additional payment from us. See the footnote titled Commitments

and Contingencies to our condensed consolidated financial statements included elsewhere in this report for additional details regarding these agreements.

DCP started-up the first of the two plants in August 2018. This reduced, but did not eliminate, the elevated line pressure and capacity constraints we experienced during the third quarter of 2018. The reliability of the new plant and compression is improving, but reductions in line pressures have been intermittent as DCP transitions from start-up to more stable long-term operations and production growth by us and other operators in the field continues to grow. DCP is currently scheduled to start-up the second facility during the second quarter of 2019. We have been engaged with DCP in planning for further incremental increases to their processing capacity in the field. 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. If Proposition 112 is approved by the voters, it could result in reduced investments in midstream infrastructure in the Wattenberg Field going forward. See Item 1A. Risk Factors - If approved by voters, Proposition 112 would impose severe limits on the number of permissible drilling locations in the Wattenberg Field, thereby adversely affecting our future growth and numerous other aspects of our business.

In addition, beginning in August 2018, residue gas takeaway capacity constraints limited gathering system throughput because the incremental residue volumes associated with a new plant exceeded the available residue takeaway capacity. This constraint is expected to be alleviated by residue pipeline expansion projects that are scheduled to be completed during November 2018. Further, 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 have not historically been impacted by NGL fractionation capacity constraints, the limitation on NGL fractionation capacity could limit the ability of gas processing plants to adjust ethane and propane recoveries to optimize the plant product mix to maximize revenue. Additional fractionation capacity is scheduled to come online during 2019 and 2020.

Delaware Basin. 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 approximately 85 percent of our forecasted 2018 and 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 between 88 and 92 percent of West Texas Intermediate ("WTI") crude oil pricing for our total Delaware Basin production through the remainder of 2018 and 2019, after deducting transportation and other related marketing expenses. Our actual realization for all Delaware Basin production for the third quarter of 2018 was 94 percent of WTI crude oil pricing. If necessary, we also have the option of transporting a portion of our crude oil production via truck or rail; however, doing so would decrease the realized prices we receive, in part due to a current trucking shortage in the basin. 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. We expect to install additional compression in the Central area during the fourth quarter of 2018 to ensure that all of our Central area gas volumes are delivered to market.

Our production from the Delaware Basin was not materially affected by midstream or downstream capacity constraints during the three and nine months ended September 30, 2018. However, product 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.

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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 NGLs prices have a high degree of volatility and our realizations can change substantially. Our realized sales prices for crude oil and NGLs increased during the three and nine months ended September 30, 2018 compared to the three and nine months ended September 30, 2017. NYMEX average daily crude oil prices increased 44 percent and 35 percent and NYMEX first-of-the-month natural gas prices decreased three percent and nine percent for the three and nine months ended September 30, 2018, respectively, as compared to the respective periods in 2017.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
Weighted-Average Realized Sales Price by Operating Region (excluding net settlements on derivatives)	2018	2017	Percentage Change	2018	2017	Percentage Change
Crude oil (per Bbl)						
Wattenberg Field	$66.49	$45.80	45.2 %	$63.53	$46.84	35.6 %
Delaware Basin	65.58	45.06	45.5 %	63.19	46.05	37.2 %
Utica Shale (1)	—	43.03	(100.0)%	58.10	44.51	30.5 %
Weighted-average price	66.27	45.66	45.1 %	63.43	46.69	35.9 %
Natural gas (per Mcf)						
Wattenberg Field	$1.65	$2.09	(21.1)%	$1.66	$2.23	(25.6)%
Delaware Basin	1.41	2.74	(48.5)%	1.65	2.13	(22.5)%
Utica Shale (1)	—	1.81	(100.0)%	2.68	2.56	4.7 %
Weighted-average price	1.60	2.17	(26.3)%	1.67	2.23	(25.1)%
NGLs (per Bbl)						
Wattenberg Field	$22.38	$17.49	28.0 %	$20.76	$16.68	24.5 %
Delaware Basin	30.42	20.87	45.8 %	29.29	20.02	46.3 %
Utica Shale (1)	—	22.00	(100.0)%	24.29	22.40	8.4 %
Weighted-average price	24.35	18.11	34.5 %	22.71	17.24	31.7 %
Crude oil equivalent (per Boe)						
Wattenberg Field	$36.49	$27.33	33.5 %	$34.65	$27.44	26.3 %
Delaware Basin	38.12	28.07	35.8 %	37.78	27.65	36.6 %
Utica Shale (1)	—	23.75	(100.0)%	30.98	26.98	14.8 %
Weighted-average price	36.88	27.35	34.8 %	35.35	27.45	28.8 %

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 the three and nine months ended September 30, 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.

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 condensed 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.

For the Three Months Ended September 30, 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)	$ 69.50	$ 66.27	95 %	$ 1.05	$ 65.22	94 %
Natural gas (per MMBtu)	2.90	1.60	55 %	0.20	1.40	48 %
NGLs (per Bbl)	69.50	24.35	35 %	0.18	24.17	35 %
Crude oil equivalent (per Boe)	50.79	36.88	73 %	0.91	35.97	71 %

For the Three Months Ended September 30, 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)	$ 48.20	$	45.66	95	%	$ 1.41	$ 44.25	92	%
Natural gas (per MMBtu)	3.00		2.17	72	%	0.24	1.93	64	%
NGLs (per Bbl)	48.20		18.11	38	%	0.25	17.86	37	%
Crude oil equivalent (per Boe)	36.92		27.35	74	%	1.15	26.20	71	%

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For the Nine Months Ended September 30, 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)	$ 66.75	$ 63.43	95 %	$ 0.89	$ 62.54	94 %
Natural gas (per MMBtu)	2.90	1.67	58 %	0.22	1.45	50 %
NGLs (per Bbl)	66.75	22.71	34 %	0.20	22.51	34 %
Crude oil equivalent (per Boe)	48.78	35.35	72 %	0.90	34.45	71 %

For the Nine Months Ended September 30, 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)	$ 49.47	$ 46.69	94 %	$ 1.42	$ 45.27	92 %
Natural gas (per MMBtu)	3.17	2.23	70 %	0.15	2.08	66 %
NGLs (per Bbl)	49.47	17.24	35 %	0.29	16.95	34 %
Crude oil equivalent (per Boe)	37.99	27.45	72 %	0.96	26.49	70 %

Our average realization percentages for crude oil and NGLs for the three and nine months ended September 30, 2018 are consistent with those for the comparable periods of 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 condensed consolidated financial statements included elsewhere in this report for a detailed presentation of our derivative positions as of September 30, 2018.

Commodity price risk management, net, includes cash settlements upon maturity of our derivative instruments, as well as the change in 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 settlement 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 derivatives included in commodity price risk management, net:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Commodity price risk management gain (loss), net:				
Net settlements of commodity derivative instruments:				
Crude oil fixed price swaps, collars and rollfactors	$(53.6)	$5.4	$(117.6)	$7.4
Crude oil basis protection swaps	2.0	—	13.5	—
Natural gas fixed price swaps and collars	0.5	5.1	3.1	13.5
Natural gas basis protection swaps	4.3	1.2	15.6	3.3
NGLs (propane portion) fixed price swaps	(1.3)	(2.1)	(5.1)	(2.0)
Total net settlements of commodity derivative instruments	(48.1)	9.6	(90.5)	22.2
Change in fair value of unsettled commodity derivative instruments:				
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	56.6	(15.6)	47.9	31.0
Crude oil fixed price swaps, collars and rollfactors	(101.4)	(40.0)	(213.8)	26.3
Natural gas fixed price swaps and collars	(0.8)	(2.1)	(2.1)	9.2
Natural gas basis protection swaps	0.2	1.5	2.6	3.4
NGLs (propane portion) fixed price swaps	(0.9)	(5.6)	(1.9)	(5.6)
Net change in fair value of unsettled commodity derivative instruments	(46.3)	(61.8)	(167.3)	64.3
Total commodity price risk management gain (loss), net	$(94.4)	$(52.2)	$(257.8)	$86.5

Our decrease in net settlements for the nine months ended September 30, 2018 was partially offset by an $11.3 million realized gain on the early settlement of certain commodity derivative basis protection positions, including $10.3 million for the early settlement of crude oil basis protection instruments and $1.0 million for the early settlement of natural gas basis protection instruments, both for our Delaware Basin operations. The volumes associated with these instruments were impacted by certain marketing agreements entered into during the nine months ended September 30, 2018, which eliminated the underlying sale price variability, and therefore there was no longer a variable to hedge.

Lease Operating Expenses

Lease operating expenses increased 30 percent to $33.0 million in the three months ended September 30, 2018 compared to $25.4 million in the three months ended September 30, 2017. The increase was primarily due to increases of $2.4 million for increased workover projects, $1.3 million for payroll and employee benefits primarily related to increases in headcount, $1.2 million related to additional compressor and equipment rentals to combat high line pressures and $1.0 million related to midstream expense in the Delaware Basin. Lease operating expense per Boe increased by 10 percent to $3.27 for the three months ended September 30, 2018 from $2.98 for the three months ended September 30, 2017.

Lease operating expenses increased 46 percent to $94.9 million in the nine months ended September 30, 2018 compared to $65.2 million in the nine months ended September 30, 2017. The increase was primarily due to increases of $7.0 million for increased workover projects, $4.4 million for payroll and employee benefits primarily related to increases in headcount, $4.2 million related to additional compressor and equipment rentals to combat high line pressures, $3.5 million related to midstream expense in the Delaware Basin, $2.9 million for environmental remediation expenses and $1.8 million for produced water disposal and $1.0 million related to chemical treatment programs. Lease operating expense per Boe increased by 19 percent to $3.34 for the nine months ended September 30, 2018 from $2.81 for the nine months ended September 30, 2017.

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Production Taxes

Production taxes are comprised mainly of severance tax and ad valorem tax and 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 certain credits that are determined based upon activity levels and relative commodity prices from year-to-year.

Production taxes increased 55 percent to $24.0 million in the three months ended September 30, 2018 compared to $15.5 million in the three months ended September 30, 2017, primarily due to the 60 percent increase in crude oil, natural gas and NGLs sales for the three months ended September 30, 2018 compared to the three months ended September 30, 2017.

Production taxes increased 55 percent to $66.8 million in the nine months ended September 30, 2018 compared to $43.0 million in the nine months ended September 30, 2017, primarily due to the 58 percent increase in crude oil, natural gas and NGLs sales for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017, as well as an increase in the ad valorem tax rate in the Delaware Basin related to an increase in assessed property values.

Transportation, Gathering and Processing Expenses

Transportation, gathering and processing expenses decreased six percent to $9.2 million in the three months ended September 30, 2018 compared to the three months ended September 30, 2017 and increased 15 percent to $25.5 million in the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017. Transportation, gathering and processing expenses are primarily impacted by variances in the volumes delivered through pipelines and for natural gas gathering and transportation operations. The changes as compared to the respective periods of 2017 are 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Exploratory dry hole costs	$0.1	$41.2	$0.1	$41.2
Geological and geophysical costs, including seismic purchases	0.5	0.5	2.2	1.8
Operating, personnel and other	0.4	0.2	2.3	0.9
Total exploration, geologic and geophysical expense	$1.0	$41.9	$4.6	$43.9

Exploratory dry hole costs. During the three and nine months ended September 30, 2017, two exploratory dry hole wells, associated lease costs and related infrastructure assets in the Delaware Basin were expensed at a cost of $41.2 million. The conclusion to expense these items was due to the determination that the acreage on which these wells were drilled was exploratory in nature and, following drilling, the lack of hydrocarbon production necessary for the wells to be deemed economically viable. There were no significant comparable exploratory dry hole costs during the three or nine months ended September 30, 2018.

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Impairment of Properties and Equipment

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Impairment of proved and unproved properties	$1.5	$252.6	$194.1	$282.2
Amortization of individually insignificant unproved properties	—	0.1	0.1	0.3
Impairment of crude oil and natural gas properties	$1.5	$252.7	$194.2	$282.5

During the nine months ended September 30, 2018, we recorded impairment charges totaling $194.2 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 both widening oil and gas differentials and increased well development costs. We expect that approximately 13,000 gross and net Delaware Basin acres primarily in the western area block in Culberson County will expire by the end of the first quarter of 2019 as a result of normal course expirations of leases that we do not expect to renew due to an expected lack of economically recoverable production quantities. These acres were impaired to an immaterial value in 2017 and 2018. In total for the Delaware Basin, approximately 16 percent, 36 percent and four percent of the leaseholds are at risk to expire in the fourth quarter of 2018, 2019 and 2020, respectively. We intend to focus our future Delaware Basin development in our oilier core areas where we have identified approximately 450 mid-length lateral equivalent Wolfcamp drilling locations. We continue to explore options for our non-focus areas and monitor them for possible future impairment based on similar analyses.

During the nine months ended September 30, 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 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. The amount of the impairment was based on the value assigned to individual lease acres in the final purchase price allocation of the business combination. 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.

Additionally, during the nine months ended September 30, 2017, we recorded impairment charges of $27.0 million for certain unproved Delaware Basin leaseholds positions that expired or were projected to expire between June 30, 2017 and December 31, 2017. Subsequent to closing the acquisitions in the Delaware Basin, it was determined that development of certain acreage tracts would not meet our internal expectations for acceptable rates of return due to a combination of weakening commodity prices, higher per well development and operational costs and updated technical analysis. As a result, we allowed certain acreage to expire, and in other circumstances we were unable to obtain necessary lease term extensions.

Impairment of Goodwill

During the three months ended September 30, 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. In addition to the factors mentioned above, we also considered impairments of certain unproven leasehold costs recorded during the same period and the impact of these items on our internal expectations for acceptable rates of return.

General and Administrative Expense

General and administrative expense increased 65 percent to $48.2 million in the three months ended September 30, 2018 compared to $29.3 million in the three months ended September 30, 2017. The increase was primarily attributable to a $7.6 million increase in legal-related costs, a $5.8 million increase in government relations expenses, a $2.4 million increase in payroll and employee benefits and a $1.6 million increase related to environmental matters.

General and administrative expense increased 42 percent to $121.2 million in the nine months ended September 30, 2018 compared to $85.1 million in the nine months ended September 30, 2017. The increase was primarily attributable to a $12.7 million increase in payroll and employee benefits, a $7.6 million increase in government relations expenses, a $5.9 million increase in legal-related costs, a $4.4 million increase related to professional services, a $1.6 million increase related to environmental matters, and a $1.1 million increase in software licenses and subscriptions.

Depreciation, Depletion and Amortization Expense

Crude oil and natural gas properties. 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 $145.4 million and $403.8 million for the three and nine months ended September 30, 2018, respectively, compared to $123.6 million and $355.7 million for the three and nine months ended September 30, 2017, respectively.

The period-over-period change in DD&A expense related to crude oil and natural gas properties was primarily due to the following:

	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
	(in thousands)	
Increase in production	$25,207	$ 82,943
Decrease in weighted-average depreciation, depletion and amortization rates	(3,376)	(34,911)
Total increase in DD&A expense related to crude oil and natural gas properties	$21,831	$ 48,032

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Region/Area	2018	2017	2018	2017
	(per Boe)			
Wattenberg Field	$12.51	$14.60	$12.98	$15.53
Delaware Basin	20.43	15.14	18.70	15.32
Utica Shale (1)	—	7.64	—	10.21
Total weighted-average	$14.40	$14.52	$14.22	$15.35

(1) 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 the properties.

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $2.1 million and $6.2 million for the three and nine months ended September 30, 2018, respectively, compared to $1.7 million and $4.8 million for the three and nine months ended September 30, 2017, respectively.

Interest Expense

Interest expense decreased $1.7 million to $17.6 million for the three months ended September 30, 2018 compared to $19.3 million for the three months ended September 30, 2017. The decrease was primarily related to a $10.0 million decrease in interest expense relating to the net settlement of previously outstanding senior notes in December 2017 and a $1.0 million increase in capitalized interest. The decreases were partially offset by an $8.8 million increase in interest expense related to the issuance of our 2026 Senior Notes in November 2017.

Interest expense decreased $5.8 million to $52.6 million for the nine months ended September 30, 2018 compared to $58.4 million for the nine months ended September 30, 2017. The decrease was primarily related to a $29.9 million decrease in interest expense relating to the net settlement of previously outstanding senior notes in December 2017 and a $3.0 million increase in capitalized interest. The decreases were partially offset by a $26.4 million increase in interest expense related to the issuance of our 2026 Senior Notes in November 2017.

Provision for Income Taxes

The effective income tax rates for the three and nine months ended September 30, 2018 were 53.0 percent and 23.3 percent benefit on loss, respectively, compared to 29.5 percent and 25.8 percent benefit on loss, respectively, for the three and nine months ended September 30, 2017. The effective income tax rates are based upon a full year forecasted pre-tax loss for the year adjusted for permanent differences. The quarterly rates are proportionately impacted by updates to previously-forecasted pre-tax income (loss). The federal corporate statutory income tax rate decreased from 35 percent in 2017 to 21 percent in 2018 pursuant to the 2017 Tax Act.

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

The factors resulting in net loss in the three and nine months ended September 30, 2018 of $3.4 million and $176.8 million, respectively, and a net loss in the three and nine months ended September 30, 2017 of $292.5 million and $205.1 million, respectively, are discussed above. Adjusted net income, a non-U.S. GAAP financial measure, was $31.8 million for the three months ended September 30, 2018 and adjusted net loss was $49.6 million for the nine months ended September 30, 2018. Adjusted net loss was $253.9 million and $245.4 million for the three and nine months ended September 30, 2017, respectively. With the exception of the tax affected net change in fair value of unsettled derivatives of $35.2 million and $127.2 million for the three and nine months ended September 30, 2018, respectively, and $38.6 million and $40.3 million for the three and nine months ended September 30, 2017, respectively, these same factors impacted adjusted net income (loss), a non-U.S. GAAP financial measure. See Reconciliation of Non-U.S. GAAP Financial Measures below for a more detailed discussion of these non-U.S. GAAP financial measures and a reconciliation of these measures to the most comparable U.S. GAAP measures.

Financial Condition, Liquidity and Capital Resources

Our primary sources of liquidity are cash flows from operating activities, our revolving credit facility, proceeds raised in debt and equity capital market transactions and asset sales. For the nine months ended September 30, 2018, our net cash flows from operating activities were $577.8 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 term. Based upon our current hedge position and assuming forward strip pricing as of September 30, 2018, our derivatives are expected to be a source of net cash outflow in the near term.

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. We had working capital deficits of $417.8 million and $16.4 million at September 30, 2018 and December 31, 2017, respectively. The increase in working capital deficit as of September 30, 2018 of $401.4 million is primarily the result of a decrease in cash and cash equivalents of $179.3 million related to the Bayswater Asset Acquisition and a decrease in the net fair value of our unsettled commodity derivative instruments of $132.5 million, partially offset by the proceeds received from the Utica Shale Divestiture, proceeds from an amendment to a midstream dedication agreement, and an increase in accounts payable of $101.0 million related to increased development and exploration activity.

Our cash and cash equivalents were $1.4 million at September 30, 2018 and availability under our revolving credit facility was $625.0 million, providing for a total liquidity position of $626.4 million as of September 30, 2018. In October 2018, we increased the commitment level on our revolving credit facility to the current borrowing base amount of $1.3 billion. Assuming a commitment level of $1.3 billion on our revolving credit facility at September 30, 2018, our total liquidity position would have been approximately $1.23 billion. Based on the pricing assumptions described in Executive Summary - Liquidity, we expect our 2018 capital investments in crude oil and natural gas properties, excluding acquisitions and corporate capital, to exceed our 2018 cash flows from operations by $125 million to $150 million, of which approximately $65 million was financed by an amendment to a midstream oil dedication agreement that occurred in January 2018 and the divestiture of our Utica Shale properties that occurred in March 2018. The increase in the anticipated outspend can primarily be attributed to the impact on our production of continued elevated line pressures in the Wattenberg Field. We experienced the outspend during the first nine months of 2018 and expect cash flows from operations to exceed capital investment during the remainder of the year. As a result, we expect to be minimally drawn on our credit facility at December 31, 2018, subject to potential borrowings to satisfy short-term working capital needs.

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 September 30, 2018, we were in compliance with all covenants in the revolving credit facility with a leverage ratio of 1.6:1.0 and a current ratio of 1.9:1.0. 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 condensed 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 from operating activities increased by $157.2 million to $577.8 million for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017, primarily due to increases in crude oil, natural gas and NGLs sales of $367.6 million. This increase was offset in part by a decrease in commodity derivative settlements of $112.7 million and increases in general and administrative expenses of $36.0 million, lease operating expenses of $29.8 million and production taxes of $23.8 million.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $167.7 million to $575.3 million during the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017. The increase was primarily due to the same factors mentioned above for changes in cash flows provided by operating activities, without regard to timing of cash payments and receipts of assets and liabilities. Adjusted EBITDAX, a non-U.S. GAAP financial measure, increased by $120.3 million during the nine months ended September 30, 2018, compared to the nine months ended September 30, 2017. The increase was primarily the result of an increase in crude oil, natural gas and NGLs sales of $367.6 million. This increase was partially offset by a decrease in commodity derivative settlements of $112.7 million, the reversal of a provision for uncollectible notes receivable of $40.2 million in the nine months ended September 30, 2017 and increases in general and administrative expenses of $36.0 million, lease operating expenses of $29.8 million and production taxes of $23.8 million. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of 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 need to continue to commit significant amounts of capital in order to maintain and grow our production and replace our reserves. If capital is not available or is constrained 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 $823.7

million during the nine months ended September 30, 2018 was primarily related to cash utilized toward the purchase price of the Bayswater Asset Acquisition of $181.0 million and our drilling and completion activities of $685.5 million. Partially offsetting these investments was the receipt of approximately $39.0 million related to the Utica Shale Divestiture.

Financing Activities. Net cash received from financing activities of $65.3 million during the nine months ended September 30, 2018 was primarily comprised of net borrowings from our credit facility of $75.0 million, which was partially offset by $4.7 million related to purchases of our stock and $4.1 million of debt issuance costs, primarily related to our Restated Credit Agreement.

Off-Balance Sheet Arrangements

At September 30, 2018, we had no off-balance sheet arrangements, as defined under SEC rules, which have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital investments or capital resources.

Commitments and Contingencies

See the footnote titled Commitments and Contingencies to the accompanying condensed consolidated financial statements included elsewhere in this report.

Recent Accounting Standards

See the footnote titled Summary of Significant Accounting Policies to the accompanying condensed consolidated financial statements included elsewhere in this report.

Critical Accounting Policies and Estimates

The preparation of the accompanying condensed consolidated financial statements in conformity with U.S. GAAP required management to use judgment in making estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses.

There have been no significant changes to our critical accounting policies and estimates or in the underlying accounting assumptions and estimates used in these critical accounting policies from those disclosed in the condensed consolidated financial statements and accompanying notes contained in our 2017 Form 10-K filed with the SEC on February 27, 2018 and amended on May 1, 2018.

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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Adjusted cash flows from operations:				
Net cash from operating activities	$197.0	$148.2	$577.8	$420.7
Changes in assets and liabilities	4.1	2.7	(2.5)	(13.1)
Adjusted cash flows from operations	$201.1	$150.9	$575.3	$407.6
Adjusted net loss:				
Net loss	$(3.4)	$(292.5)	$(176.8)	$(205.1)
(Gain) loss on commodity derivative instruments	94.4	52.2	257.8	(86.5)
Net settlements on commodity derivative instruments	(48.1)	9.6	(90.5)	22.2
Tax effect of above adjustments	(11.1)	(23.2)	(40.1)	24.0
Adjusted net income (loss)	$31.8	$(253.9)	$(49.6)	$(245.4)
Net loss to adjusted EBITDAX:				
Net loss	$(3.4)	$(292.5)	$(176.8)	$(205.1)
(Gain) loss on commodity derivative instruments	94.4	52.2	257.8	(86.5)
Net settlements on commodity derivative instruments	(48.1)	9.6	(90.5)	22.2
Non-cash stock-based compensation	5.6	4.8	16.4	14.6
Interest expense, net	17.4	18.8	52.2	56.9
Income tax benefit	(3.9)	(122.4)	(53.8)	(71.5)
Impairment of properties and equipment	1.5	252.7	194.2	282.5
Impairment of goodwill	—	75.1	—	75.1
Exploration, geologic and geophysical expense	1.0	41.9	4.6	43.9
Depreciation, depletion and amortization	147.5	125.2	410.0	360.6
Accretion of asset retirement obligations	1.2	1.5	3.8	4.9
Adjusted EBITDAX	$213.2	$166.9	$617.9	$497.6
Cash from operating activities to adjusted EBITDAX:				
Net cash from operating activities	$197.0	$148.2	$577.8	$420.7
Interest expense, net	17.4	18.8	52.2	56.9
Amortization of debt discount and issuance costs	(3.1)	(3.2)	(9.5)	(9.6)
Gain (loss) on sale of properties and equipment	(2.1)	0.1	(3.2)	0.8
Exploration, geologic and geophysical expense	1.0	41.9	4.6	43.9
Exploratory dry hole costs	—	(41.2)	—	(41.2)
Other	(1.1)	(0.4)	(1.5)	39.2
Changes in assets and liabilities	4.1	2.7	(2.5)	(13.1)
Adjusted EBITDAX	$213.2	$166.9	$617.9	$497.6

ITEM 3. 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, cash equivalents and restricted cash accounts 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 September 30, 2018, our interest-bearing deposit accounts included money market accounts and checking accounts with various banks. The amount of our interest-bearing cash, cash equivalents and restricted cash as of September 30, 2018 was $0.6 million with a weighted-average interest rate of 1.2 percent. Based on a sensitivity analysis of our interest-bearing deposits as of September 30, 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 had a material impact on interest income for the nine months ended September 30, 2018.

As of September 30, 2018, we had $75.0 million outstanding balance on our revolving credit facility. If market interest rates would have increased or decreased one percent, our interest expense for the nine months ended September 30, 2018 would have changed 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, natural gas basis 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. See the footnote titled Commodity Derivative Financial Instruments to our condensed consolidated financial statements included elsewhere in this report for a description of our open commodity derivative positions at September 30, 2018.

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:

	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
Average NYMEX Index Price:			
Crude oil (per Bbl)	$ 69.50	$ 66.75	$ 50.95
Natural gas (per MMBtu)	2.90	2.90	3.11
Average Sales Price Realized:			

Excluding net settlements on commodity derivatives			
Crude oil (per Bbl)	$ 66.27	$ 63.43	$ 48.45
Natural gas (per Mcf)	1.60	1.67	2.21
NGLs (per Bbl)	24.35	22.71	18.59

Based on a sensitivity analysis as of September 30, 2018, we estimate that a ten percent increase in natural gas, crude oil 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 $104.7 million, whereas a ten percent decrease in prices would have resulted in an increase in fair value of $102.8 million.

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Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform 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 counterparty’s 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 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, including major upstream and midstream energy companies, financial institutions and end-users in various industries. 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 relating 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, collection and related claims against certain third-party producers that are delinquent in their payment obligations, which have to date resulted in two default judgments. We expect this trend to continue for this business.

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 condensed 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 September 30, 2018, it does not consider those exposures or positions which could arise after that date. As a result, 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 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of September 30, 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 pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e). 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 September 30, 2018 because of the material weaknesses in our internal control over financial reporting described below.

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 Chief Executive Officer and Chief Financial Officer, 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.

During 2017, 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 of our unproved properties, impairment of unproved properties, sales, accounts receivable and depletion expense accounts and related disclosures during 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.

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 for the year ended December 31, 2018. We have taken the necessary steps to strengthen the underlying control activities, which include the combination of hiring of additional personnel with prior relevant experience, increased layers of supervision and division of responsibilities in the Land Department. We have also developed controls to verify the completeness and accuracy of land administrative records associated with unproved leases, including controls to verify the reliability of reports used in such controls. These material weaknesses will not be considered remediated until the applicable remedial 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 September 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II
ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

We face many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described under Item 1A, Risk Factors, of our 2017 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

There have been no material changes from the risk factors previously disclosed in our 2017 Form 10-K, except for the following:

If approved by voters, Proposition 112 would impose severe limits on the number of permissible drilling locations in the Wattenberg Field, thereby adversely affecting our future growth and numerous other aspects of our business.

As discussed in “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Regulatory Update,” certain interest groups in Colorado opposed to new oil and natural gas development generally, and hydraulic fracturing in particular, have sponsored an initiative, now known as Proposition 112, that will be voted on with a November 6, 2018 voting deadline. If approved, Proposition 112 would result in new crude oil and natural gas development in the state being essentially eliminated. The proposal would take effect by the end of 2018. Proposition 112 would require all new oil and gas development facilities to be located at least 2,500 feet away from any occupied structure or “vulnerable areas,” very broadly defined to include playgrounds, permanent sports fields, amphitheaters, public parks, public open space, public and community drinking water sources, irrigation canals, reservoirs, lakes, rivers, perennial or intermittent streams and creeks and any additional vulnerable areas designated by the state or a local

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government. The current minimum required setback between oil and gas development facilities and occupied structures is generally 500 feet and 1,000 feet from high-occupancy structures such as schools or apartment buildings. Federal lands would be excluded from Proposition 112.

If implemented, Proposition 112 would have a highly material and adverse effect on our results of operations, financial condition, proved undeveloped and non-proved reserves, future growth and future drilling inventory. In particular:

- The combined effect of Proposition 112's increased setback requirement and expansive definition of the term "vulnerable areas" would be to eliminate the vast majority of our future drilling inventory in the Wattenberg Field. The Colorado Oil and Gas Conservation Commission has estimated that implementation of the proposition would make drilling unlawful on approximately 85 percent of the non-federal surface land of the state of Colorado and approximately 85 percent of the non-federal land in Weld County, where a significant part of our assets are located. In addition, the remaining areas available for development would likely shrink in the future as additional occupied structures are built and additional "vulnerable areas" are designated as such. Implementation of the proposition would therefore make it impossible to continue to pursue our current development plans.
- The reduction in drilling inventory that would result from the implementation of Proposition 112 would result in a corresponding reduction in our proved undeveloped and non-proved reserves in the Wattenberg Field. This would also likely result in a reduction in the borrowing base under our revolving credit facility and make it more difficult for us to obtain other forms of financing. It would also make it more difficult for us to satisfy our volume commitments relating to production from the field, increasing the risk that we will be obligated to pay monetary penalties to the counterparties under those contracts.
- Proposition 112 would reduce our projected growth in future years by reducing capital investment, cash flow and free cash flow. It would also reduce our ability to improve our leverage ratio in future years.
- Given the numerous ambiguities in the text of Proposition 112, our expectation that we could continue to drill currently permitted locations, and complete DUCs, even if the proposition passes could prove to be incorrect. We could face an increased risk of litigation relating to these or other similar issues and, even if we are successful in such litigation, we would incur increased legal costs. Similarly, it is possible that there will be legislative or regulatory action to clarify or amend aspects of the proposition, and we cannot predict the outcome of any such action. Any litigation or legislative or regulatory process relating to the implementation of the proposition, even if it resulted in us being able to drill our permitted locations and complete our DUCs, could impose delays or otherwise interfere with the development of our remaining locations in the field.
- The implementation of Proposition 112 would likely have the effect of reducing investment in midstream infrastructure in the Wattenberg Field. In particular, DCP may delay or postpone completion of a plant and/or may eliminate other planned or proposed midstream infrastructure projects beyond those to which it is contractually committed. This could result in increased capacity constraints over the next two years and, in turn, increased curtailment of production, larger price differentials and reduced netbacks. We anticipate that other operators in the field would, like us, likely respond to the passage of the proposition by seeking to drill all of their permitted locations before the expiration of the relevant permits. This could result in increased field-wide production, and resulting increases in capacity constraints, at a time when providers of midstream infrastructure and services would be reducing or eliminating additional investments in the field. A field-wide increase in development activities could also have other adverse effects, such as an increase in drilling and completion costs resulting from greater demand for services, as well as the potential for greater operating costs due to increased demand for services and equipment.
- We could incur other costs and liabilities relating to a reduction in the scope of our activities if Proposition 112 is implemented. For example, a decline in the market price of our common stock could reduce the retentive effect of equity compensation awards we have granted and increase litigation risks. In addition, we could incur charges associated with a reduction in the scale of our Wattenberg Field operations.

We may face some of the risks described above even if Proposition 112 is rejected by the voters. For instance, if the proposition fails, increased capacity constraints could result as midstream providers potentially alter the pace of additional investments and/or operators potentially adjust the pace of planned development activities out of concern that a similar ballot initiative will be proposed in the future. In addition, it is possible that the Colorado legislature or regulatory authorities would respond to the concerns underlying the proposition by imposing additional restrictions on development activities that would adversely affect our operations.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
July 1 - 31, 2018	3,187	$ 61.17
August 1 - 31, 2018	—	—
September 1 - 30, 2018	215	48.86
Total third quarter 2018 purchases	3,402	$ 60.39

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(1) Purchases 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.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES - None.

ITEM 4. MINE SAFETY DISCLOSURES - Not applicable.

ITEM 5. OTHER INFORMATION - None.

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PDC ENERGY, INC.

ITEM 6. EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
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.					
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 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.
(Registrant)

Date: November 5, 2018 /s/ Barton Brookman
Barton Brookman
President and Chief Executive Officer
(principal executive officer)

/s/ R. Scott Meyers
R. Scott Meyers
Senior Vice President and Chief Financial Officer
(principal financial officer)