CABOT OIL & GAS CORP
Form 10-Q
October 26, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q
ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
For the quarterly period ended September 30, 2018
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
Commission file number 1-10447

CABOT OIL & GAS CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE	04-3072771
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Three Memorial City Plaza
840 Gessner Road, Suite 1400, Houston, Texas 77024
(Address of principal executive offices including ZIP code)
(281) 589-4600
(Registrant’s telephone number, including area code)

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 and (2) has been subject to such filing requirements for the past 90 days. Yes ý 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 ý 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 the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company” and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ý	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 ý
As of October 25, 2018, there were 431,179,872 shares of Common Stock, Par Value $0.10 Per Share, outstanding.

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ITEM 1. Financial Statements
CABOT OIL & GAS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEET (Unaudited)

(In thousands, except share amounts)	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 316,077	$ 480,047
Accounts receivable, net	222,827	216,004
Income taxes receivable	65,792	56,666
Inventories	12,476	8,006
Current assets held for sale	—	1,440
Other current assets	2,692	2,794
Total current assets	619,864	764,957
Properties and equipment, net (Successful efforts method)	3,366,237	3,072,204
Equity method investments	157,934	86,077
Assets held for sale	6,114	778,855
Derivative instruments	1,248	2,239
Other assets	27,646	23,012
	$ 4,179,043	$ 4,727,344
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 263,623	$ 238,045
Current portion of long-term debt	67,000	304,000
Accrued liabilities	15,453	27,441
Interest payable	9,101	27,575
Derivative instruments	10,921	30,637
Current liabilities held for sale	—	2,352
Total current liabilities	366,098	630,050
Long-term debt, net	1,218,848	1,217,891
Deferred income taxes	358,708	227,030
Asset retirement obligations	48,205	43,601
Liabilities held for sale	381	15,748
Postretirement benefits	30,769	29,396
Other liabilities	61,887	39,723
Total liabilities	2,084,896	2,203,439
Commitments and contingencies		
Stockholders' equity		
Common stock:		
Authorized — 960,000,000 shares of $0.10 par value in 2018 and 2017, respectively		
Issued — 476,089,105 shares and 475,547,419 shares in 2018 and 2017, respectively	47,609	47,555
Additional paid-in capital	1,756,337	1,742,419
Retained earnings	1,362,797	1,162,430
Accumulated other comprehensive income	2,112	2,077
Less treasury stock, at cost:		
42,080,250 shares and 14,935,926 shares in 2018 and 2017, respectively	(1,074,708)	(430,576)
Total stockholders' equity	2,094,147	2,523,905
	$ 4,179,043	$ 4,727,344

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

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CABOT OIL & GAS CORPORATION
CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands, except per share amounts)	2018	2017	2018	2017
OPERATING REVENUES				
Natural gas	$440,835	$323,319	$1,217,603	$1,152,089
Crude oil and condensate	—	56,913	48,722	144,528
Gain (loss) on derivative instruments	(3,537)	(836)	(1,628)	46,353
Brokered natural gas	105,849	3,528	203,375	12,260
Other	2,026	2,492	3,775	8,486
	545,173	385,416	1,471,847	1,363,716
OPERATING EXPENSES				
Direct operations	17,030	26,282	52,757	78,185
Transportation and gathering	129,534	117,891	355,848	361,909
Brokered natural gas	93,405	2,797	178,437	10,262
Taxes other than income	2,852	9,194	15,434	26,562
Exploration	10,049	6,466	68,166	16,623
Depreciation, depletion and amortization	121,172	146,267	288,210	425,689
Impairment of oil and gas properties	—	—	—	68,555
General and administrative	20,724	23,244	66,013	70,902
	394,766	332,141	1,024,865	1,058,687
Loss on equity method investments	(11)	(1,417)	(1,009)	(3,986)
Gain (loss) on sale of assets	25,655	(11,872)	(14,850)	(13,498)
INCOME FROM OPERATIONS	176,051	39,986	431,123	287,545
Interest expense, net	14,191	20,331	57,577	61,720
Other expense (income)	115	(5,083)	347	(4,974)
Income before income taxes	161,745	24,738	373,199	230,799
Income tax expense	39,408	7,151	91,201	85,965
NET INCOME	$122,337	$17,587	$281,998	$144,834
Earnings per share				
Basic	$0.28	$0.04	$0.63	$0.31
Diluted	$0.28	$0.04	$0.62	$0.31
Weighted-average common shares outstanding				
Basic	440,772	462,498	450,445	464,194
Diluted	443,110	464,780	452,313	466,010
Dividends per common share	$0.06	$0.05	$0.18	$0.12

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

CABOT OIL & GAS CORPORATION
CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS (Unaudited)

	Nine Months Ended September 30,	
(In thousands)	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$281,998	$144,834
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	288,210	425,689
Impairment of oil and gas properties	—	68,555
Deferred income tax expense	131,799	89,731
Loss on sale of assets	14,850	13,498
Exploratory dry hole cost	56,425	2,842
(Gain) loss on derivative instruments	1,628	(46,353)
Net cash received (paid) in settlement of derivative instruments	(20,354)	3,587
Loss on equity method investments	1,009	3,986
Amortization of debt issuance costs	3,521	3,579
Stock-based compensation and other	16,472	26,011
Changes in assets and liabilities:		
Accounts receivable, net	(7,345)	29,276
Income taxes	(14,447)	(16,665)
Inventories	(5,326)	(2,100)
Other current assets	104	(896)
Accounts payable and accrued liabilities	32,192	(5,133)
Interest payable	(18,474)	(15,318)
Other assets and liabilities	26,590	(6,076)
Net cash provided by operating activities	788,852	719,047
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(647,503)	(586,813)
Proceeds from sale of assets	675,525	32,711
Investment in equity method investments	(72,866)	(23,382)
Net cash used in investing activities	(44,844)	(577,484)
CASH FLOWS FROM FINANCING ACTIVITIES		
Repayments of debt	(237,000)	—
Treasury stock repurchases	(581,725)	(68,255)
Dividends paid	(81,185)	(55,707)
Tax withholdings on vesting of stock awards	(8,068)	(5,929)
Other	—	42
Net cash used in financing activities	(907,978)	(129,849)
Net increase (decrease) in cash and cash equivalents	(163,970)	11,714
Cash and cash equivalents, beginning of period	480,047	498,542
Cash and cash equivalents, end of period	$316,077	$510,256

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

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. Financial Statement Presentation

During interim periods, Cabot Oil & Gas Corporation (the Company) follows the same accounting policies disclosed in its Annual Report on Form 10-K/A for the year ended December 31, 2017 (Form 10-K/A) filed with the Securities and Exchange Commission (SEC). The interim financial statements should be read in conjunction with the notes to the consolidated financial statements and information presented in the Form 10-K/A. In management’s opinion, the accompanying interim condensed consolidated financial statements contain all material adjustments, consisting only of normal recurring adjustments, necessary for a fair statement. The results for any interim period are not necessarily indicative of the expected results for the entire year.

Certain reclassifications have been made to prior year statements to conform with the current year presentation. These reclassifications had no impact on previously reported stockholders' equity, net income or cash flows.

Recently Adopted Accounting Pronouncements

Revenue Recognition. In May 2014, the Financial Accounting Standards Boards (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (Topic 606) (Accounting Standards Codification (ASC) 606, as subsequently amended). ASC 606 supersedes the revenue recognition requirements in Topic 605 Revenue Recognition (ASC 605), and requires entities to recognize revenue when control of the promised goods or services is transferred to customers at an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services. The Company adopted ASC 606 as of January 1, 2018 using the modified retrospective transition method.

The adoption of ASC 606 also included the adoption and modification of other guidance, particularly the creation of ASC 340-40 on costs to obtain or fulfill contracts with customers and ASC 610-20 on gains or losses on derecognition of nonfinancial assets. ASC 340-40 provides additional capitalization, amortization and impairment guidance for certain costs associated with obtaining or fulfilling contracts subject to ASC 606. ASC 610-20 provides guidance on the measurement and recognition of gains and losses for disposals of assets that are not the outputs of ordinary activities, such as sales of fixed assets, when they are not businesses or deconsolidation of subsidiaries. The guidance in ASC 610-20 largely aligns with the guidance in ASC 606. It also supersedes most guidance on real estate sales that was contained in ASC 360-20; however, it does not apply to conveyances of oil and gas interests, which continue to be governed by guidance in ASC 932 for oil and gas extractive activities.

There was no material effect from the adoption of ASC 340-40 or ASC 610-20 separate from those discussed from the adoption of ASC 606.

Financial Instruments. In January 2016, the FASB issued ASU 2016-01, Financial Instruments - Overall, as an amendment to ASC Subtopic 825-10. The amendments in this update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. Among other items, this update will simplify the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment. When a qualitative assessment indicates that impairment exists, an entity is required to measure the investment at fair value. This impairment assessment reduces the complexity of the other-than-temporary impairment guidance that entities follow currently. The Company adopted ASU 2016-01 as of January 1, 2018. The adoption of this guidance did not have a material effect on the Company's financial position, results of operation or cash flows.

Statement of Cash Flows. In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230), which is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The guidance addresses eight specific cash flow issues for which current accounting guidance is either unclear or does not include specific guidance. The Company adopted this guidance effective January 1, 2018. In conjunction with the adoption, the Company made an accounting policy election to classify distributions it receives from its equity method investees based on the nature of distributions approach in which distributions received are classified on the basis of the nature of the activity that generated the distribution as either a return on investment (cash inflows from operating activities) or a return of investment (cash inflows from investing activities). The adoption of this guidance did not have a material effect on the Company's financial position, results of operation or cash flows.

Recently Issued Accounting Pronouncements

Leases. In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). The new lease guidance supersedes Topic 840. The core principle of the guidance is that entities should recognize the assets and liabilities that arise from leases.

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This ASU does not apply to leases to explore for or use minerals, oil, natural gas and similar nonregenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained. The guidance is effective for interim and annual periods beginning after December 15, 2018. This ASU is to be adopted using a modified retrospective approach. The Company plans to adopt this guidance effective January 1, 2019 by applying the transition approach as of the beginning of the period of adoption. Comparative periods will not be restated.

The Company plans to make use of the following practical expedients which are provided in the leases standard:

- an election not to apply the recognition requirements in the leases standard to short-term leases (a lease that at commencement date has a lease term of 12 months or less and does not contain a purchase option that the Company is reasonably certain to exercise);
- a package of practical expedients to not reassess whether a contract is or contains a lease, lease classification and initial direct costs;
- a practical expedient to use hindsight when determining the lease term; and
- a practical expedient to not reassess certain land easements in existence prior to January 1, 2019.

The Company is currently evaluating the effect that adopting this guidance will have on its financial position, results of operations or cash flows.

Revenue Recognition

On January 1, 2018, the Company adopted ASC 606, Revenue from Contracts with Customers, and the related guidance in ASC 340-40 (the new revenue standard), and related guidance on gains and losses on derecognition of nonfinancial assets ASC 610-20, using the modified retrospective method applied to those contracts which were not completed as of January 1, 2018. Under the modified retrospective method, the Company recognizes the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of retained earnings; however, no significant adjustment was required as a result of adopting the new revenue standard. Results for reporting periods beginning after January 1, 2018 are presented under the new revenue standard. The comparative information has not been restated and continues to be reported under the historic accounting standards in effect for those periods.

The Company's revenue is typically generated from contracts to sell natural gas, crude oil or NGLs produced from interests in oil and gas properties owned by the Company. These contracts generally require the Company to deliver a specific amount of a commodity per day for a specified number of days at a price that is either fixed or variable. The contracts specify a delivery point which represents the point at which control of the product is transferred to the customer. These contracts frequently meet the definition of a derivative under ASC 815, and are accounted for as derivatives unless the Company elects to treat them as normal sales as permitted under that guidance. The Company typically elects to treat contracts to sell oil and gas production as normal sales, which are then accounted for as contracts with customers. The Company has determined that these contracts represent multiple performance obligations which are satisfied when control of the commodity transfers to the customer, typically through the delivery of the specified commodity to a designated delivery point.

Revenue is measured based on consideration specified in the contract with the customer, and excludes any amounts collected on behalf of third parties. The Company recognizes revenue in the amount that reflects the consideration it expects to be entitled to in exchange for transferring control of those goods to the customer. The contract consideration in the Company's variable price contracts are typically allocated to specific performance obligations in the contract according to the price stated in the contract. Amounts allocated in the Company's fixed price contracts are based on the standalone selling price of those products in the context of long-term, fixed price contracts, which generally approximates the contract price. Payment is generally received one or two months after the sale has occurred.

Gain or loss on derivative instruments is outside the scope of ASC 606 and is not considered revenue from contracts with customers subject to ASC 606. The Company may use financial or physical contracts accounted for as derivatives as economic hedges to manage price risk associated with normal sales, or in limited cases may use them for contracts the Company intends to physically settle but do not meet all of the criteria to be treated as normal sales.

Taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction, and that are collected by the Company from a customer, are excluded from revenue.
Producer Gas Imbalances. The Company applies the sales method of accounting for natural gas revenue. Under this method, revenues are recognized based on the actual volume of natural gas sold to purchasers. Natural gas production operations may include joint owners who take more or less than the production volumes entitled to them on certain properties.

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Production volume is monitored to minimize these natural gas imbalances. Under this method, a natural gas imbalance liability is recorded if the Company's excess takes of natural gas exceed its estimated remaining proved developed reserves for these properties at the actual price realized upon the gas sale. A receivable is recognized only to the extent an imbalance cannot be recouped from the reserves in the underlying properties. The Company’s aggregate imbalance positions at September 30, 2018 and December 31, 2017 were not material.

Brokered Natural Gas. Revenues and expenses related to brokered natural gas are reported gross as part of operating revenues and operating expenses in accordance with applicable accounting standards. The Company buys and sells natural gas utilizing separate purchase and sale transactions whereby the Company or the counterparty obtains control of the natural gas purchased or sold.

Disaggregation of Revenue. The following table presents revenues disaggregated by product:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands)	2018	2017	2018	2017
OPERATING REVENUES				
Natural gas	$440,835	$323,319	$1,217,603	$1,152,089
Crude oil and condensate	—	56,913	48,722	144,528
Brokered natural gas	105,849	3,528	203,375	12,260
Other	2,026	2,492	3,775	8,486
Total revenues from contracts with customers	548,710	386,252	1,473,475	1,317,363
Gain (loss) on derivative instruments	(3,537)	(836)	(1,628)	46,353
Total operating revenues	$545,173	$385,416	$1,471,847	$1,363,716

All of the Company’s revenues from contracts with customers represent products transferred at a point in time as control is transferred to the customer and are generated in the United States.

Transaction Price Allocated to Remaining Performance Obligations. A significant number of the Company’s product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

As of September 30, 2018, the Company has $9.2 billion of unsatisfied performance obligations related to natural gas sales that have a fixed pricing component and a contract term greater than one year. The Company expects to recognize these obligations over the next 10 to 20 years.

Contract Balances. Receivables from contracts with customers are recorded when the right to consideration becomes unconditional, generally when control of the product has been transferred to the customer. Receivables from contracts with customers were $221.5 million and $215.5 million as of September 30, 2018 and December 31, 2017, respectively, and are reported in accounts receivable, net on the Condensed Consolidated Balance Sheet. The Company currently has no assets or liabilities related to its revenue contracts, including no upfront or rights to deficiency payments.

Practical Expedients. The Company has made use of certain practical expedients in adopting the new revenue standard, including the value of unsatisfied performance obligations are not disclosed for (i) contracts with an original expected length of one year or less, (ii) contracts for which the Company recognizes revenue at the amount to which the Company has the right to invoice, (iii) contracts with variable consideration which is allocated entirely to a wholly unsatisfied performance obligation and meets the variable allocation criteria in the standard and (iv) only contracts that are not completed at transition.

The Company has not adjusted the promised amount of consideration for the effects of a significant financing component if the Company expects, at contract inception, that the period between when the Company transfers a promised good or service to the customer and when the customer pays for that good or service will be one year or less.

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2. Properties and Equipment, Net

Properties and equipment, net are comprised of the following:

(In thousands)	September 30, 2018	December 31, 2017
Proved oil and gas properties	$ 5,489,836	$ 4,932,512
Unproved oil and gas properties	199,219	190,474
Gathering and pipeline systems	1,569	1,569
Land, building and other equipment	86,953	82,670
	5,777,577	5,207,225
Accumulated depreciation, depletion and amortization	(2,411,340)	(2,135,021)
	$ 3,366,237	$ 3,072,204

At September 30, 2018, the Company did not have any projects that had exploratory well costs capitalized for a period of greater than one year after drilling.

Divestitures

In July 2018, the Company sold its operated and non-operated oil and gas properties in the Haynesville Shale for $30.0 million. The sales price included a $5.0 million deposit that was received in the fourth quarter of 2017. During the fourth quarter of 2017, the Company classified these assets as held for sale. The Company recognized a gain on sale of oil and gas properties of $29.5 million.

In February 2018, the Company sold its operated and non-operated Eagle Ford Shale assets for $765.0 million. During the fourth quarter of 2017, the Company classified these assets as held for sale and recorded an impairment charge of $414.3 million associated with the proposed sale of these properties. The Company recognized a loss on sale of oil and gas properties of $45.2 million.

3. Equity Method Investments

The Company holds a 25% equity interest in Constitution Pipeline Company, LLC (Constitution) and a 20% equity interest in Meade Pipeline Co LLC (Meade). Activity related to these equity method investments is as follows:

	Constitution		Meade		Total	
	Nine Months Ended September 30,					
(In thousands)	2018	2017	2018	2017	2018	2017
Balance at beginning of period	$732	$96,850	$85,345	$32,674	$86,077	$129,524
Contributions	250	3,750	72,616	19,632	72,866	23,382
Loss on equity method investments	(982)	(3,971)	(27)	(15)	(1,009)	(3,986)
Balance at end of period	$—	$96,629	$157,934	$52,291	$157,934	$148,920

During 2018, the Company expects to contribute approximately $70.0 million to its equity method investments. For further information regarding the Company’s equity method investments, refer to Note 4 of the Notes to the Consolidated Financial Statements in the Form 10-K/A.

Meade

In February 2014, the Company acquired a 20% equity interest in Meade, which was formed to participate in the development and construction of a 177-mile pipeline (Central Penn Line) that will transport natural gas from Susquehanna County, Pennsylvania to interconnect with Transcontinental Gas Pipe Line Company, LLC’s (Transco) mainline in Lancaster County, Pennsylvania. The Central Penn Line is operated by Transco and is owned by Transco and Meade in proportion to their respective ownership percentages of approximately 61% and 39%, respectively. By order issued on February 3, 2017, the Federal Energy Regulatory Commission (FERC) issued Transco a certificate of public convenience and necessity authorizing the construction of the new pipeline. Subsequently on October 4, 2018, the FERC issued a notice granting Authorization to Place the Facilities into service and on October 9, 2018, Transco notified the FERC that the Central Penn Line was placed into service on October 6, 2018.

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On August 14, 2018, the Company entered into a precedent agreement with Transco for up to 250,000 Dth per day of firm transportation capacity on Transco's proposed Leidy South expansion project. The Company will also be participating as an equity owner in the expansion project through its ownership in Meade and expects to contribute approximately $17.8 million, its proportionate share of the anticipated costs of the expansion project. The expansion project is anticipated to be in-service as early as the fourth quarter of 2021, assuming all necessary regulatory approvals are received in a timely manner and construction proceeds on schedule.

Constitution

As of September 30, 2018, the Company’s carrying value of its investment in Constitution is less than its proportionate share of Constitution’s net assets by $95.9 million. This basis difference is due to the Company’s impairment recorded in the fourth quarter of 2017 and relates entirely to the pipeline assets of Constitution. The Company expects to amortize this basis difference once the related assets of Constitution are placed in service, which may or may not occur, depending on the outcome of the legal and regulatory process related to certain permitting matters.

The Company remains committed to funding the project in an amount proportionate to its ownership interest for the development and construction of the new pipeline.

4. Debt and Credit Agreements

The Company’s debt and credit agreements consisted of the following:

(In thousands)	September 30, 2018	December 31, 2017
Total debt		
6.51% weighted-average senior notes [1]	$ 124,000	$ 361,000
9.78% senior notes [2]	67,000	67,000
5.58% weighted-average senior notes	175,000	175,000
3.65% weighted-average senior notes	925,000	925,000
Revolving credit facility	—	—
Unamortized debt issuance costs	(5,152)	(6,109)
	$ 1,285,848	$ 1,521,891

(1) Includes $237.0 million of current portion of long-term debt at December 31, 2017, which the Company paid in July 2018.

(2) Includes $67.0 million of current portion of long-term debt at September 30, 2018 and December 31, 2017, respectively.

The borrowing base under the terms of the Company's revolving credit facility is redetermined annually in April. In addition, either the Company or the banks may request an interim redetermination twice a year or in connection with certain acquisitions or divestitures of oil and gas properties. Effective April 18, 2018, the borrowing base and available commitments were reaffirmed at $3.2 billion and $1.7 billion, respectively. At September 30, 2018, the Company had no borrowings outstanding under its revolving credit facility and had unused commitments of $1.8 billion.

At September 30, 2018, the Company was in compliance with all restrictive financial covenants for both its revolving credit facility and senior notes.

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5. Derivative Instruments and Hedging Activities

As of September 30, 2018, the Company had the following outstanding financial commodity derivatives:

Type of Contract	Volume	Contract Period	Swaps Weighted-Average	Basis Swaps Weighted-Average
Natural gas (Leidy)	8.9 Bcf	Oct. 2018 - Dec. 2018		$ (0.69)
Natural gas (Leidy)	53.2 Bcf	Jan. 2019 - Dec. 2019		$ (0.55)
Natural gas (Transco)	13.3 Bcf	Oct. 2018 - Dec. 2019		$ 0.42
Natural gas (NYMEX)	23.2 Bcf	Oct. 2018 - Dec. 2018	$ 2.93	
Natural gas (NYMEX)	1.5 Bcf	Oct. 2018	$ 3.10	

In the table above, natural gas prices are stated per Mcf.

Effect of Derivative Instruments on the Condensed Consolidated Balance Sheet

(In thousands)	Balance Sheet Location	Derivative Assets September 30, 2018	Derivative Assets December 31, 2017	Derivative Liabilities September 30, 2018	Derivative Liabilities December 31, 2017
Commodity contracts	Derivative instruments (current)	$ —	$ —	$ 10,921	$ 30,637
Commodity contracts	Derivative instruments (non-current)	1,248	2,239	—	—
		$ 1,248	$ 2,239	$ 10,921	$ 30,637

Offsetting of Derivative Assets and Liabilities in the Condensed Consolidated Balance Sheet

(In thousands)	September 30, 2018	December 31, 2017
Derivative assets		
Gross amounts of recognized assets	$ 1,273	$ 2,239
Gross amounts offset in the statement of financial position	(25)	—
Net amounts of assets presented in the statement of financial position	1,248	2,239
Gross amounts of financial instruments not offset in the statement of financial position	—	—
Net amount	$ 1,248	$ 2,239
Derivative liabilities		
Gross amounts of recognized liabilities	$ 10,946	$ 30,637
Gross amounts offset in the statement of financial position	(25)	—
Net amounts of liabilities presented in the statement of financial position	10,921	30,637
Gross amounts of financial instruments not offset in the statement of financial position	—	241
Net amount	$ 10,921	$ 30,878

Effect of Derivative Instruments on the Condensed Consolidated Statement of Operations

(In thousands)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Cash received (paid) on settlement of derivative instruments				
Gain (loss) on derivative instruments	$(41)	$3,906	$(20,354)	$3,587
Non-cash gain (loss) on derivative instruments				
Gain (loss) on derivative instruments	(3,496)	(4,742)	18,726	42,766
	$(3,537)	$(836)	$(1,628)	$46,353

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6. Fair Value Measurements

The Company follows the authoritative guidance for measuring fair value of assets and liabilities in its financial statements. For further information regarding the fair value hierarchy, refer to Note 1 of the Notes to the Consolidated Financial Statements in the Form 10-K/A.

Financial Assets and Liabilities

The following fair value hierarchy table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis:

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at September 30, 2018
Assets				
Deferred compensation plan	$ 16,671	$ —	$ —	$ 16,671
Derivative instruments	—	—	1,273	1,273
Total assets	$ 16,671	$ —	$ 1,273	$ 17,944
Liabilities				
Deferred compensation plan	$ 27,835	$ —	$ —	$ 27,835
Derivative instruments	—	4,722	6,224	10,946
Total liabilities	$ 27,835	$ 4,722	$ 6,224	$ 38,781

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2017
Assets				
Deferred compensation plan	$ 14,966	$ —	$ —	$ 14,966
Derivative instruments	—	—	2,239	2,239
Total assets	$ 14,966	$ —	$ 2,239	$ 17,205
Liabilities				
Deferred compensation plan	$ 29,145	$ —	$ —	$ 29,145
Derivative instruments	—	—	30,637	30,637
Total liabilities	$ 29,145	$ —	$ 30,637	$ 59,782

The Company's investments associated with its deferred compensation plan consist of mutual funds and deferred shares of the Company's common stock that are publicly traded and for which market prices are readily available.

The derivative instruments were measured based on quotes from the Company's counterparties or internal models. Such quotes and models have been derived using an income approach that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, basis differentials and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. Estimates are verified using relevant NYMEX futures contracts and/or are compared to multiple quotes obtained from counterparties for reasonableness. The determination of the fair values presented above also incorporates a credit adjustment for non-performance risk. The Company measured the non-performance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions with which it has derivative transactions, while non-performance risk of the Company is evaluated using a market credit spread provided by the Company's bank. The Company has not incurred any losses related to non-performance risk of its counterparties and does not anticipate any material impact on its financial results due to non-performance by third parties.

The most significant unobservable inputs relative to the Company's Level 3 derivative contracts are basis differentials. An increase (decrease) in these unobservable inputs would result in an increase (decrease) in fair value, respectively. The Company does not have access to the specific assumptions used in its counterparties' valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided.

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The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

(In thousands)	Nine Months Ended September 30, 2018	2017
Balance at beginning of period	$(28,398)	$(15,868)
Total gain (loss) included in earnings	6,333	28,659
Settlement (gain) loss	17,114	(7,114)
Transfers in and/or out of level 3	—	—
Balance at end of period	$(4,951)	$5,677
Change in unrealized gain (loss) relating to assets and liabilities still held at the end of the period	$(6,685)	$14,431

There were no transfers between Level 1 and Level 2 fair value measurements for the nine months ended September 30, 2018 and 2017.

Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as impairments, at fair value on a nonrecurring basis. As none of the Company's other non-financial assets and liabilities were measured at fair value as of September 30, 2018, additional disclosures were not required.

The estimated fair value of the Company's asset retirement obligations at inception is determined by utilizing the income approach by applying a credit-adjusted risk-free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the measurement of the asset retirement obligations was classified as Level 3 in the fair value hierarchy.

Fair Value of Other Financial Instruments

The estimated fair value of other financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amount reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents approximates fair value due to the short-term maturities of these instruments. Cash and cash equivalents are classified as Level 1 in the fair value hierarchy and the remaining financial instruments are classified as Level 2.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount the Company would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Company's default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company's senior notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all senior notes and the revolving credit facility is based on interest rates currently available to the Company. The Company's debt is valued using an income approach and classified as Level 3 in the fair value hierarchy.

The carrying amount and fair value of debt is as follows:

	September 30, 2018		December 31, 2017	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$1,285,848	$1,245,971	$1,521,891	$1,527,624
Current maturities	(67,000)	(67,679)	(304,000)	(312,055)
Long-term debt, excluding current maturities	$1,218,848	$1,178,292	$1,217,891	$1,215,569

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7. Asset Retirement Obligations

Activity related to the Company’s asset retirement obligations is as follows:

(In thousands)	Nine Months Ended September 30, 2018
Balance at beginning of period[1]	$ 48,553
Liabilities incurred	3,592
Liabilities settled	(1,025)
Liabilities divested	(3,782)
Accretion expense	1,867
Balance at end of period[2]	$ 49,205

(1) Includes $5.0 million of current asset retirement obligations included in accrued liabilities at December 31, 2017.
(2) Includes $1.0 million of current asset retirement obligations included in accrued liabilities at September 30, 2018.

8. Commitments and Contingencies

Contractual Obligations

The Company has various contractual obligations in the normal course of its operations. There have been no material changes to the Company’s contractual obligations described under “Transportation and Gathering Agreements” and "Lease Commitments” as disclosed in Note 9 of the Notes to Consolidated Financial Statements in the Form 10-K/A.

Legal Matters

The Company is a defendant in various legal proceedings arising in the normal course of business. All known liabilities are accrued when management determines they are probable based on its best estimate of the potential loss. While the outcome and impact of these legal proceedings on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings will not have a material effect on the Company’s financial position, results of operations or cash flows.

Contingency Reserves. When deemed necessary, the Company establishes reserves for certain legal proceedings. The establishment of a reserve is based on an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur additional losses with respect to those matters in which reserves have been established. The Company believes that any such amount above the amounts accrued would not be material to the Condensed Consolidated Financial Statements. Future changes in facts and circumstances not currently foreseeable could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

9. Capital Stock

Treasury Stock

In February 2018, the Board of Directors authorized an increase of 25.0 million shares to the Company’s share repurchase program. In July 2018, the Board of Directors authorized an increase of an additional 20.0 million shares to the Company’s share repurchase program. After the most recent authorization, the total number of shares available for repurchase was 30.1 million shares. Under the share repurchase program, the Company may purchase shares of common stock in the open market or in negotiated transactions. The timing and amount of any stock purchases are determined at the discretion of management. The Company may use the repurchased shares to fund stock compensation programs currently in existence or for other corporate purposes. All purchases executed to date have been through open market transactions. There is no expiration date associated with the authorization to repurchase common stock of the Company.

During the first nine months of 2018, the Company repurchased 27.1 million shares for a total cost of $644.2 million. As of September 30, 2018, 22.9 million shares are available for repurchase under the share repurchase program.

As of September 30, 2018, 42.1 million shares were held as treasury stock, which includes 2.7 million shares that were repurchased prior to September 30, 2018 and settled in October 2018.

Subsequent Event. Subsequent to September 30, 2018, the Company repurchased 2.8 million shares for a total cost of $65.6 million under a Rule 10b5-1 Plan.

In October 2018, the Board of Directors approved an increase in the quarterly dividend on our common stock from $0.06 per share to $0.07 per share.

10. Stock-based Compensation

General

From time to time the Company grants certain stock-based compensation awards, including restricted stock awards, restricted stock units and performance share awards. Stock-based compensation expense associated with these awards was $6.5 million and $7.8 million in the third quarter of 2018 and 2017, respectively, and $17.6 million and $26.2 million during the first nine months of 2018 and 2017, respectively. Stock-based compensation expense is included in general and administrative expense in the Condensed Consolidated Statement of Operations.

Refer to Note 13 of the Notes to the Consolidated Financial Statements in the Form 10-K/A for further description of the various types of stock-based compensation awards and the applicable award terms.

Restricted Stock Units

During the first nine months of 2018, 80,131 restricted stock units were granted to non-employee directors of the Company with a weighted-average grant date value of $23.45 per unit. The fair value of these units is measured based on the closing stock price on grant date and compensation expense is recorded immediately. These units immediately vest and are issued when the director ceases to be a director of the Company.

Performance Share Awards

The performance period for the awards granted during the first nine months of 2018 commenced on January 1, 2018 and ends on December 31, 2020. The Company used an annual forfeiture rate assumption ranging from 0% to 5% for purposes of recognizing stock-based compensation expense for its performance share awards.

Performance Share Awards Based on Internal Performance Metrics

The fair value of performance share award grants based on internal performance metrics is based on the closing stock price on the grant date. Each performance share award represents the right to receive up to 100% of the award in shares of common stock. Based on the Company's probability assessment at September 30, 2018, it is considered probable that the criteria for all performance awards based on internal metrics awards will be met.

Employee Performance Share Awards. During the first nine months of 2018, 531,670 Employee Performance Share Awards were granted at a grant date value of $23.25 per share. The performance metrics are set by the Company's compensation committee and are based on the Company's average production, average finding costs and average reserve replacement over a three-year performance period.

Hybrid Performance Share Awards. During the first nine months of 2018, 321,720 Hybrid Performance Share Awards were granted at a grant date value of $23.25 per share. The 2018 awards vest 25% on each of the first and second anniversary dates and 50% on the third anniversary, provided that the Company has $100 million or more of operating cash flow for the year preceding the vesting date, as set by the Company's compensation committee. If the Company does not meet the performance metric for the applicable period, then the portion of the performance shares that would have been issued on that anniversary date will be forfeited.

Performance Share Awards Based on Market Conditions

These awards have both an equity and liability component, with the right to receive up to the first 100% of the award in shares of common stock and the right to receive up to an additional 100% of the value of the award in excess of the equity component in cash. The equity portion of these awards is valued on the grant date and is not marked to market, while the liability portion of the awards is valued as of the end of each reporting period on a mark-to-market basis. The Company calculates the fair value of the equity and liability portions of the awards using a Monte Carlo simulation model.

TSR Performance Share Awards. During the first nine months of 2018, 482,581 TSR Performance Share Awards were granted and are earned, or not earned, based on the comparative performance of the Company's common stock measured against a predetermined group of companies in the Company's peer group over a three-year performance period.

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The following assumptions were used to determine the grant date fair value of the equity component (February 21, 2018) and the period-end fair value of the liability component of the TSR Performance Share Awards:

	Grant Date	September 30, 2018
Fair value per performance share award	$ 19.92	$2.46-$12.02
Assumptions:		
Stock price volatility	37.3 %	26.1% - 29.9%
Risk free rate of return	2.40 %	2.18% - 2.81%

11. Earnings per Common Share

Basic earnings per share (EPS) is computed by dividing net income by the weighted-average number of common shares outstanding for the period. Diluted EPS is similarly calculated except that the common shares outstanding for the period is increased using the treasury stock method to reflect the potential dilution that could occur if outstanding stock appreciation rights were exercised and stock awards were vested at the end of the applicable period.

Anti-dilutive shares represent potentially dilutive securities that are excluded from the computation of diluted income or loss per share as their impact would be anti-dilutive.

The following is a calculation of basic and diluted weighted-average shares outstanding:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands)	2018	2017	2018	2017
Weighted-average shares - basic	440,772	462,498	450,445	464,194
Dilution effect of stock appreciation rights and stock awards at end of period	2,338	2,282	1,868	1,816
Weighted-average shares - diluted	443,110	464,780	452,313	466,010

The following is a calculation of weighted-average shares excluded from diluted EPS due to the anti-dilutive effect:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands)	2018	2017	2018	2017
Weighted-average stock appreciation rights and stock awards excluded from diluted EPS due to the anti-dilutive effect calculated using the treasury stock method	1	2	1	6

12. Income Taxes

On December 22, 2017, the U.S. enacted tax legislation referred to as the Tax Cuts and Jobs Act (the Tax Act) which significantly changes U.S. corporate income tax laws beginning, generally, in 2018. These changes include, among others, (i) a permanent reduction of the U.S. corporate income tax rate from a top marginal rate of 35% to a flat rate of 21%, (ii) elimination of the corporate alternative minimum tax, (iii) immediate deductions for certain new investments instead of deductions for depreciation expense over time, (iv) limitation on the tax deduction for interest expense to 30% of adjusted taxable income, (v) limitation of the deduction for net operating losses to 80% of current year taxable income and elimination of net operating loss carrybacks, and (vi) elimination of many business deductions and credits, including the domestic production activities deduction, the deduction for entertainment expenditures, and the deduction for certain executive compensation in excess of $1 million. The Company included the impacts of the Tax Act in the fourth quarter 2017 consolidated financial statements, and no changes were made to those provisional amounts during the first nine months of 2018. The Company will continue to examine the impact of this legislation and future regulations. Additional impacts from the enactment of the Tax Act will be recorded as they are identified during the measurement period as provided for in SAB No. 118, which extends up to one year from the enactment date. The 2018 tax provision reflects the legislative changes noted above, including the new corporate tax rate of 21%. Income tax expense for the first nine months of 2018 increased $5.2 million compared to the first nine months of 2017 due to higher pre-tax income, partially offset by a lower effective tax rate. The effective tax rates for the first nine months of 2018 and 2017 were 24.4% and 37.2%, respectively. The decrease in the effective tax rate is primarily due to the impact of the Tax Act law changes that were effective January 1, 2018, partially offset by an increase in the blended state statutory tax rate as a result of changes in the Company's state apportionment factors due to the Eagle Ford Shale asset divestiture in February 2018.

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As of September 30, 2018, the Company had a $19.3 million net reserve for unrecognized tax benefits primarily related to alternative minimum tax (AMT) associated with uncertain tax positions, and a $3.7 million liability for accrued interest associated with the uncertain tax positions. Any additional AMT payments could be utilized as credits against future regular tax liabilities and would be fully refunded from 2018 through 2021 under the new Tax Act. Accordingly, the uncertain tax positions identified would not have a material impact on the Company's effective tax rate.

13. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

(In thousands)	September 30, 2018	December 31, 2017
Accounts receivable, net		
Trade accounts	$ 221,515	$ 215,511
Joint interest accounts	1,916	467
Other accounts	852	1,312
	224,283	217,290
Allowance for doubtful accounts	(1,456)	(1,286)
	$ 222,827	$ 216,004
Other assets		
Deferred compensation plan	$ 16,671	$ 14,966
Debt issuance costs	5,427	7,990
Income taxes receivable	5,321	—
Other accounts	227	56
	$ 27,646	$ 23,012
Accounts payable		
Trade accounts	$ 34,869	$ 7,815
Natural gas purchases	36,115	4,299
Royalty and other owners	33,206	39,207
Accrued transportation	47,934	51,433
Accrued capital costs	33,150	31,130
Taxes other than income	11,787	16,801
Deposits received for asset sales	—	81,500
Other accounts	66,562	5,860
	$ 263,623	$ 238,045
Accrued liabilities		
Employee benefits	$ 12,970	$ 20,645
Taxes other than income	1,708	550
Asset retirement obligations	1,000	4,952
Other accounts	(225)	1,294
	$ 15,453	$ 27,441
Other liabilities		
Deferred compensation plan	$ 27,835	$ 29,145
Other accounts	34,052	10,578
	$ 61,887	$ 39,723

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ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following review of operations for the three and nine month periods ended September 30, 2018 and 2017 should be read in conjunction with our Condensed Consolidated Financial Statements and the Notes included in this Form 10-Q and with the Consolidated Financial Statements, Notes and Management's Discussion and Analysis included in the Cabot Oil & Gas Corporation Annual Report on Form 10-K/A for the year ended December 31, 2017 (Form 10-K/A).

OVERVIEW

Financial and Operating Overview

Financial and operating results for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017 are as follows:

- Natural gas production increased 32.4 Bcf, or 6.6%, from 491.2 Bcf in 2017 to 523.6 Bcf in 2018, as a result of drilling and completion activities in Pennsylvania.
- Crude oil/condensate/NGL production decreased 2.8 Mmbbls, or 77%, from 3.6 Mmbbls in 2017 to 0.8 Mmbbls in 2018, as result of the sale of our Eagle Ford Shale assets in February 2018.
- Equivalent production increased 16.0 Bcfe, or 3.1%, from 512.7 Bcfe, or 1,877.9 Mmcfe per day, in 2017 to 528.6 Bcfe, or 1,936.4 Mmcfe per day, in 2018. The increase is primarily due to drilling and completion activities in Pennsylvania, partially offset by the sale of our Eagle Ford Shale assets in south Texas.
- Average realized natural gas price was $2.32 per Mcf, 1% lower than the $2.35 per Mcf realized in the comparable period of the prior year.
- Average realized crude oil price was $63.72 per Bbl, 39% higher than the $45.70 per Bbl realized in the comparable period of the prior year.
- Total capital expenditures were $593.1 million compared to $582.8 million in the comparable period of the prior year.
- Drilled 60 gross wells (60.0 net) with a success rate of 91.7% compared to 71 gross wells (62.5 net) with a success rate of 98.6% for the comparable period of the prior year.
- Completed 61 gross wells (61.0 net) in 2018 compared to 81 gross wells (70.2 net) in 2017.
- Average rig count during 2018 was approximately 3.3 rigs in the Marcellus Shale and approximately 0.7 rigs in other areas, compared to an average rig count in the Marcellus Shale of approximately 2.0 rigs, approximately 1.0 rig in the Eagle Ford Shale and approximately 0.2 rigs in other areas during 2017.
- Received net proceeds of $675.5 million primarily related to the divestiture of our Eagle Ford Shale assets in south Texas in February 2018 and Haynesville Shale assets in July 2018.
- Repaid $237.0 million of our 6.51% weighted-average senior notes which matured in July 2018.
- Repurchased 27.1 million shares of our common stock for $644.2 million in 2018.

Market Conditions and Commodity Prices

Our financial results depend on many factors, particularly commodity prices and our ability to market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by pipeline capacity constraints, inventory storage levels, basis differentials, weather conditions and other factors. In addition, our realized prices are further impacted by our hedging activities. As a result, we cannot accurately predict future commodity prices and, therefore, cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our capital program, production volumes or revenues. We expect commodity prices to remain volatile. In addition to production volumes and commodity prices, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success. For information about the impact of realized commodity prices on our revenues, refer to "Results of Operations" below.

We account for our derivative instruments on a mark-to-market basis with changes in fair value recognized in operating revenues in the Condensed Consolidated Statement of Operations. As a result of these mark-to-market adjustments, we will likely experience volatility in our earnings due to commodity price volatility. Refer to "Impact of Derivative Instruments on

Operating Revenues" below and Note 5 of the Notes to the Condensed Consolidated Financial Statements for more information.

Commodity prices have remained volatile. In the event that commodity prices significantly decline, management would test the recoverability of the carrying value of its oil and gas properties and, if necessary, record an impairment charge.

We believe that we are well-positioned to manage the challenges presented in a depressed commodity pricing environment, and that we can endure the continued volatility in current and future commodity prices by:

- Continuing to exercise discipline in our capital program with the expectation of funding our capital expenditures with cash on hand, operating cash flows, and if required, borrowings under our revolving credit facility.
- Continuing to optimize our drilling, completion and operational efficiencies, resulting in lower operating costs per unit of production.
- Continuing to manage our balance sheet, which we believe provides sufficient availability under our revolving credit facility and existing cash balances to meet our capital requirements and maintain compliance with our debt covenants.
- Continuing to manage price risk by strategically hedging our natural gas and crude oil production.

Outlook

Our full year 2018 capital spending program, the majority of which is allocated to the Marcellus Shale, includes approximately $870.0 million in capital expenditures related to our drilling and completion program, leasehold acquisitions and contributions of approximately $70.0 million to our equity method investments. All such expenditures are expected to be funded by existing cash, operating cash flow and if required, borrowings under our revolving credit facility.

In 2017, we drilled 91 gross wells (82.5 net) and completed 105 gross wells (94.2 net), of which 50 gross wells (44.3 net) were drilled but uncompleted in prior years. For the full year of 2018, we plan to drill approximately 85 gross wells (85.0 net) and complete 90 gross wells (90.0 net). We will continue to assess the natural gas environment along with our liquidity position and may increase or decrease our capital expenditures accordingly.

Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the nine months ended September 30, 2018 were from the sale of natural gas and crude oil production and proceeds from the sale of assets. These cash flows were primarily used to fund our capital expenditures, contributions to our equity method investments, principal and interest payments on debt, repurchase of shares of our common stock and payment of dividends. See below for additional discussion and analysis of cash flow.

The borrowing base under the terms of our revolving credit facility is redetermined annually in April. In addition, either we or the banks may request an interim redetermination twice a year or in connection with certain acquisitions or divestitures of oil and gas properties. Effective April 18, 2018, the borrowing base and available commitments were reaffirmed at $3.2 billion and $1.8 billion, respectively. There were no borrowings outstanding under our revolving credit facility as of September 30, 2018.

On July 2, 2018, we closed on the sale of our oil and gas properties in the Haynesville Shale for $30.0 million. The divestiture did not have an impact on our borrowing base or available commitments.

A decline in commodity prices could result in the future reduction of our borrowing base and related commitments under the revolving credit facility. Unless commodity prices decline significantly from current levels, we do not believe that any such reductions would have a significant impact on our ability to service our debt and fund our drilling program and related operations.

We strive to manage our debt at a level below the available credit line in order to maintain borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. We believe that, with the existing cash on hand, operating cash flow and availability under our revolving credit facility, we have the capacity to fund our spending plans.

At September 30, 2018, we were in compliance with all restrictive financial covenants for both the revolving credit facility and senior notes. See our Form 10-K/A for further discussion of our restrictive financial covenants.

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Cash Flows

Our cash flows from operating activities, investing activities and financing activities are as follows:

	Nine Months Ended September 30,	
(In thousands)	2018	2017
Cash flows provided by operating activities	$788,852	$719,047
Cash flows used in investing activities	(44,844)	(577,484)
Cash flows used in financing activities	(907,978)	(129,849)
Net (decrease) increase in cash and cash equivalents	$(163,970)	$11,714

Operating Activities. Operating cash flow fluctuations are substantially driven by commodity prices, changes in our production volumes and operating expenses. Prices for natural gas and crude oil have historically been volatile, primarily as a result of supply and demand for natural gas and crude oil, pipeline infrastructure constraints, basis differentials, inventory storage levels and seasonal influences. In addition, fluctuations in cash flow may result in an increase or decrease in our capital expenditures. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities.

Our working capital is substantially influenced by the variables discussed above and fluctuates based on the timing and amount of borrowings and repayments under our revolving credit facility, repayments of debt, the timing of cash collections and payments on our trade accounts receivable and payable, respectively, repurchases of our securities and changes in the fair value of our commodity derivative activity. From time to time, our working capital will reflect a deficit, while at other times it will reflect a surplus. This fluctuation is not unusual. At September 30, 2018 and December 31, 2017, we had a working capital surplus of $253.8 million and $134.9 million, respectively.

Net cash provided by operating activities in the first nine months of 2018 increased by $69.8 million compared to the first nine months of 2017. This increase was primarily due to favorable changes in working capital and other assets and liabilities and higher operating revenues, partially offset by higher cash operating expenses. The increase in operating revenues was primarily due to higher equivalent production and higher crude oil prices, partially offset by a decrease in realized natural gas prices. Average realized natural gas prices decreased by 1% and crude oil prices increased by 39%, respectively, for the first nine months of 2018 compared to the first nine months of 2017. Equivalent production increased by 3.1% for the first nine months of 2018 compared to the first nine months of 2017 due to higher natural gas production in the Marcellus Shale, offset by lower crude oil production due to the Eagle Ford Shale divestiture in February 2018.

See “Results of Operations” for additional information relative to commodity price, production and operating expense fluctuations.

Investing Activities. Cash flows used in investing activities decreased by $532.6 million for the first nine months of 2018 compared to the first nine months of 2017. The decrease was due to $642.8 million higher proceeds from the sale of assets primarily due to the divestiture of our Eagle Ford Shale assets in February 2018 and our Haynesville Shale assets in July 2018. This change was partially offset by $60.7 million higher capital expenditures and $49.5 million higher capital contributions associated with our equity method investments.

Financing Activities. Cash flows used in financing activities increased by $778.1 million for the first nine months of 2018 compared to the first nine months of 2017. This increase was primarily due to the repayment of $237.0 million of our 6.51% weighted-average senior notes which matured in July 2018, $513.5 million of higher repurchases of our common stock in 2018 compared to 2017 and $25.5 million of higher dividend payments related to an increase in our dividend rate from $0.12 per share for the first nine months of 2017 to $0.18 per share in the first nine months of 2018.

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Capitalization

Information about our capitalization is as follows:

(In thousands)	September 30, 2018	December 31, 2017
Debt [1]	$1,285,848	$1,521,891
Stockholders' equity	2,094,147	2,523,905
Total capitalization	$3,379,995	$4,045,796
Debt to total capitalization	38 %	38 %
Cash and cash equivalents	$316,077	$480,047

(1) Includes $67.0 million and $304.0 million of current portion of long-term debt at September 30, 2018 and December 31, 2017, respectively.

During the first nine months of 2018, we repurchased 27.1 million shares of our common stock for $644.2 million.

During the first nine months of 2018 and 2017, we paid dividends of $81.2 million ($0.18 per share) and $55.7 million ($0.12 per share), respectively, on our common stock.

In January 2018, the Board of Directors approved an increase in the quarterly dividend on our common stock from $0.05 per share to $0.06 per share.

Subsequent Events. Subsequent to September 30, 2018, we repurchased 2.8 million shares for a total cost of $65.6 million under a Rule 10b5-1 Plan.

In October 2018, the Board of Directors approved an increase in the quarterly dividend on our common stock from $0.06 per share to $0.07 per share.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital expenditures, excluding any significant property acquisitions, with cash generated from operations, and if required, borrowings under our revolving credit facility. We budget these expenditures based on our projected cash flows for the year.

The following table presents major components of our capital and exploration expenditures:

(In thousands)	Nine Months Ended September 30, 2018	2017
Capital expenditures		
Drilling and facilities	$551,351	$475,240
Leasehold acquisitions	27,487	97,835
Pipeline and gathering	—	597
Other	14,260	9,091
	593,098	582,763
Exploration expenditures[1]	68,166	16,623
Total	$661,264	$599,386

(1) Exploration expenditures include $56.4 million and $2.8 million of exploratory dry hole expenditures for the first nine months of 2018 and 2017, respectively.

For the full year of 2018, we plan to drill approximately 85 gross wells (85.0 net) and complete 90 gross wells (90.0 net). In 2018, our drilling program includes approximately $870.0 million in total capital expenditures compared to $757.2 million in 2017. See “Outlook” for additional information regarding the current year drilling program. We will continue to assess the natural gas and crude oil price environment along with our liquidity position and may increase or decrease our capital expenditures accordingly.

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Contractual Obligations

We have various contractual obligations in the normal course of our operations. There have been no material changes to our contractual obligations described under “Transportation and Gathering Agreements” and “Lease Commitments” as disclosed in Note 9 of the Notes to the Consolidated Financial Statements and the obligations described under “Contractual Obligations” in Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” included in our Form 10-K/A.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our Condensed Consolidated Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. See our Form 10-K/A for further discussion of our critical accounting policies.

Recently Adopted and Recently Issued Accounting Pronouncements

Refer to Note 1 of the Notes to the Condensed Consolidated Financial Statements, “Financial Statement Presentation,” for a discussion of new accounting pronouncements that affect us.

Results of Operations

Third Quarters of 2018 and 2017 Compared

We reported net income in the third quarter of 2018 of $122.3 million, or $0.28 per share, compared to net income of $17.6 million, or $0.04 per share, in the third quarter of 2017. The increase in net income was primarily due to higher operating revenues and higher gain on sale of assets, partially offset by higher operating expenses.

Revenue, Price and Volume Variances

Our revenues vary from year to year as a result of changes in commodity prices and production volumes. Below is a discussion of revenue, price and volume variances.

	Three Months Ended September 30,		Variance	
Revenue Variances (In thousands)	2018	2017	Amount	Percent
Natural gas	$440,835	$323,319	$117,516	36 %
Crude oil and condensate	—	56,913	(56,913)	(100)%
Gain (loss) on derivative instruments	(3,537)	(836)	(2,701)	323 %
Brokered natural gas	105,849	3,528	102,321	2,900 %
Other	2,026	2,492	(466)	(19)%
	$545,173	$385,416	$159,757	41 %

	Three Months Ended September 30,		Variance		Increase (Decrease) (In thousands)
	2018	2017	Amount	Percent	
Price Variances					
Natural gas	$2.36	$2.01	$0.35	17 %	$ 66,663
Volume Variances					
Natural gas (Bcf)	186.5	161.2	25.3	16 %	$ 50,853
Total					$ 117,516

Natural Gas Revenues

The increase in natural gas revenues of $117.5 million was due to higher natural gas prices and higher production. The increase in production was a result of an increase in our drilling and completion activities in Pennsylvania.

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Crude Oil and Condensate Revenues

The decrease in crude oil and condensate revenues of $56.9 million was a result of the sale of our Eagle Ford Shale assets in February 2018.

Impact of Derivative Instruments on Operating Revenues

	Three Months Ended September 30,	
(In thousands)	2018	2017
Cash received (paid) on settlement of derivative instruments		
Gain (loss) on derivative instruments	$(41)	$3,906
Non-cash gain (loss) on derivative instruments		
Gain (loss) on derivative instruments	(3,496)	(4,742)
	$(3,537)	$(836)

Brokered Natural Gas

	Three Months Ended September 30,		Variance	
(In thousands)	2018	2017	Amount	Percent
Brokered natural gas sales	$105,849	$3,528		
Brokered natural gas purchases	93,405	2,797		
Brokered natural gas margin	$12,444	$731	$11,713	1,602%

The $11.7 million increase in brokered natural gas margin is a result of an increase in brokered activity. This increase was due to higher volumes associated with natural gas purchases that were required to satisfy certain sales obligations.

Operating and Other Expenses

	Three Months Ended September 30,		Variance	
(In thousands)	2018	2017	Amount	Percent
Operating and Other Expenses				
Direct operations	$17,030	$26,282	$(9,252)	(35)%
Transportation and gathering	129,534	117,891	11,643	10%
Brokered natural gas	93,405	2,797	90,608	3,239%
Taxes other than income	2,852	9,194	(6,342)	(69)%
Exploration	10,049	6,466	3,583	55%
Depreciation, depletion and amortization	121,172	146,267	(25,095)	(17)%
General and administrative	20,724	23,244	(2,520)	(11)%
	$394,766	$332,141	$62,625	19%
Loss on equity method investments	$(11)	$(1,417)	$(1,406)	(99)%
Gain (loss) on sale of assets	25,655	(11,872)	(37,527)	(316)%
Interest expense, net	14,191	20,331	(6,140)	(30)%
Other expense (income)	115	(5,083)	5,198	(102)%
Income tax expense	39,408	7,151	32,257	451%

Total costs and expenses from operations increased by $62.6 million, or 19%, in the third quarter of 2018 compared to the same period of 2017. The primary reasons for this fluctuation are as follows:

- Direct operations decreased $9.3 million largely due to the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and Eagle Ford Shale assets in the first quarter of 2018, partially offset by an increase in operating costs primarily driven by higher Marcellus Shale production.

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- Transportation and gathering increased $11.6 million due to increased throughput as a result of higher Marcellus Shale production and slightly higher rates, partially offset by the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and Eagle Ford Shale assets in the first quarter of 2018.
- Brokered natural gas increased $90.6 million. See the preceding table titled "Brokered Natural Gas" for further analysis.
- Taxes other than income decreased $6.3 million primarily due to $1.6 million lower drilling impact fees as a result of lower rates, $3.2 million lower production taxes and $1.7 million lower ad valorem taxes both resulting from the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and Eagle Ford Shale assets in the first quarter of 2018.
- Exploration increased $3.6 million due to an increase in exploratory dry hole costs of $5.3 million. The exploratory dry hole costs in 2018 relate to our activities in one of our exploratory areas and our decision to cease further activity in that area based on the results of those activities.
- Depreciation, depletion and amortization decreased $25.1 million primarily due to lower DD&A of $40.6 million, partially offset by higher amortization of unproved properties of $15.6 million in the third quarter of 2018. DD&A decreased $52.7 million due to a lower DD&A rate of $0.46 per Mcfe for the third quarter of 2018 compared to $0.75 per Mcfe for the third quarter of 2017, partially offset by $12 .0 million related to higher production volumes in the Marcellus Shale. The lower DD&A rate was due to the sale of higher rate fields in Eagle Ford Shale and West Virginia and positive reserve revisions related to our year end reserve estimation process. Amortization of unproved properties increased due to higher amortization rates.
- General and administrative decreased $2.5 million primarily due to $1.4 million of lower stock-based compensation expense associated with certain of our market-based performance awards and $1.9 million lower employee costs and professional services. The remaining changes in other general and administrative expenses were not individually significant.

Gain (Loss) on Sale of Assets

During the third quarter of 2018, we recognized a net aggregate gain of $25.7 million primarily due to the sale of certain of our oil and gas assets in east Texas. During the third quarter of 2017, we recognized a net aggregate loss of $11.9 million primarily due to the sale of our assets in West Virginia.

Interest Expense, net

Interest expense, net decreased $6.1 million due to $3.3 million lower interest expense resulting from the repayment of $237.0 million of our 6.51% weighted-average senior notes which matured in July 2018 and $1.9 million lower interest expense related to uncertain tax positions.

Other Expense (Income)

Other income decreased $5.2 million due to a lower curtailment gain on postretirement benefits as a result of the termination of approximately 100 employees in West Virginia in 2017.

Income Tax Expense

Income tax expense increased $32.3 million due to higher pre-tax income, partially offset by a lower effective tax rate. The effective tax rates for the third quarter of 2018 and 2017 were 24.4% and 28.9%, respectively. The decrease in the effective tax rate is primarily due to the impact of the Tax Cuts and Jobs Act law changes that were effective January 1, 2018, as well as the impact of non-recurring discrete items recorded during the third quarter of 2018 as compared to the third quarter of 2017.

First Nine Months of 2018 and 2017 Compared

We reported net income in the first nine months of 2018 of $282.0 million, or $0.63 per share, compared to net income of $144.8 million, or $0.31 per share, in the first nine months of 2017. The increase in net income was primarily due to higher operating revenues and lower operating expenses.

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Revenue, Price and Volume Variances

Our revenues vary from year to year as a result of changes in commodity prices and production volumes. Below is a discussion of revenue, price and volume variances.

	Nine Months Ended September 30,		Variance	
Revenue Variances (In thousands)	2018	2017	Amount	Percent
Natural gas	$1,217,603	$1,152,089	$65,514	6 %
Crude oil and condensate	48,722	144,528	(95,806)	(66)%
Gain (loss) on derivative instruments	(1,628)	46,353	(47,981)	(104)%
Brokered natural gas	203,375	12,260	191,115	1,559 %
Other	3,775	8,486	(4,711)	(56)%
	$1,471,847	$1,363,716	$108,131	8 %

	Nine Months Ended September 30,		Variance		Increase (Decrease) (In thousands)
	2018	2017	Amount	Percent	
Price Variances					
Natural gas	$2.33	$2.35	$(0.02)	(1)%	$ (10,626)
Crude oil and condensate	$64.68	$45.13	$19.55	43 %	14,717
Total					$ 4,091
Volume Variances					
Natural gas (Bcf)	523.6	491.2	32.4	7 %	$ 76,140
Crude oil and condensate (Mbbl)	754	3,203	(2,449)	(76)%	(110,523)
Total					$ (34,383)

Natural Gas Revenues

The increase in natural gas revenues of $65.5 million was due to an increase in production, partially offset by lower natural gas prices. The increase in production was a result of an increase in our drilling and completion activities in Pennsylvania.

Crude Oil and Condensate Revenues

The decrease in crude oil and condensate revenues of $95.8 million was primarily due to lower production, partially offset by higher crude oil prices. The decrease in production was the result of the sale of our Eagle Ford Shale assets in February 2018.

Impact of Derivative Instruments on Operating Revenues

	Nine Months Ended September 30,	
(In thousands)	2018	2017
Cash received (paid) on settlement of derivative instruments		
Gain (loss) on derivative instruments	$(20,354)	$3,587
Non-cash gain (loss) on derivative instruments		
Gain (loss) on derivative instruments	18,726	42,766
	$(1,628)	$46,353

Brokered Natural Gas

	Nine Months Ended September 30,		Variance	
(In thousands)	2018	2017	Amount	Percent
Brokered natural gas sales	$203,375	$12,260		
Brokered natural gas purchases	178,437	10,262		

Brokered natural gas margin	$24,938	$1,998	$22,940	1,148%

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The $22.9 million increase in brokered natural gas margin is a result of an increase in brokered activity. This increase was due to higher volumes associated with natural gas purchases that were required to satisfy certain sales obligations.

Operating and Other Expenses

	Nine Months Ended September 30,		Variance	
(In thousands)	2018	2017	Amount	Percent
Operating and Other Expenses				
Direct operations	$52,757	$78,185	$(25,428)	(33)%
Transportation and gathering	355,848	361,909	(6,061)	(2)%
Brokered natural gas	178,437	10,262	168,175	1,639%
Taxes other than income	15,434	26,562	(11,128)	(42)%
Exploration	68,166	16,623	51,543	310%
Depreciation, depletion and amortization	288,210	425,689	(137,479)	(32)%
Impairment of oil and gas properties	—	68,555	(68,555)	(100)%
General and administrative	66,013	70,902	(4,889)	(7)%
	$1,024,865	$1,058,687	$(33,822)	(3)%
Loss on equity method investments	$(1,009)	$(3,986)	$(2,977)	(75)%
Gain (loss) on sale of assets	(14,850)	(13,498)	1,352	10%
Interest expense, net	57,577	61,720	(4,143)	(7)%
Other expense (income)	347	(4,974)	5,321	(107)%
Income tax expense	91,201	85,965	5,236	6%

Total costs and expenses from operations decreased by $33.8 million, or 3%, in the first nine months of 2018 compared to the same period of 2017. The primary reasons for this fluctuation are as follows:

- Direct operations decreased $25.4 million largely due to the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and the Eagle Ford Shale assets in the first quarter of 2018, partially offset by an increase in operating costs primarily driven by higher Marcellus Shale production.
- Transportation and gathering decreased $6.1 million largely due to the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and the Eagle Ford Shale assets in the first quarter of 2018, partially offset by an increase in costs due to higher rates and increased Marcellus Shale production.
- Brokered natural gas increased $168.2 million. See the preceding table titled "Brokered Natural Gas" for further analysis.
- Taxes other than income decreased $11.1 million primarily due to $6.0 million lower production taxes and $6.1 million lower ad valorem taxes both resulting from the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and Eagle Ford Shale assets in the first quarter of 2018.
- Exploration increased $51.5 million due to an increase in exploratory dry hole costs of $53.6 million. The exploratory dry hole costs in 2018 relate to our activities in one of our exploratory areas and our decision to cease further activity in that area based on the results of those activities.
- Depreciation, depletion and amortization decreased $137.5 million primarily due to lower DD&A of $141.9 million and lower accretion of $2.5 million, partially offset by higher amortization of unproved properties of $6.9 million. The decrease in DD&A was primarily due to a decrease of $150.4 million related to a lower DD&A rate of $0.45 per Mcfe for the first nine months of 2018 compared to $0.73 per Mcfe for the first nine months of 2017, partially offset by $11.7 million related to higher production volumes in the Marcellus Shale. The lower DD&A rate was due to the cessation of DD&A related to the sale of our higher rate Eagle Ford Shale assets that were classified as held for sale in the fourth quarter of 2017 and positive reserve revisions related to our year end reserve estimation process. Amortization of unproved properties increased due to higher amortization rates.

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- Impairment of oil and gas properties decreased $68.6 million due to the impairment of oil and gas properties and related related pipeline assets in West Virginia, Virginia and Ohio associated with the proposed sale of these properties in the third quarter of 2017.
- General and administrative decreased $4.9 million primarily due to lower stock-based compensation cost of $8.5 million associated with certain of our market-based performance awards offset by $4.6 million higher employee costs and professional services. The remaining changes in general and administrative expenses were not individually significant.

Loss on Equity Method Investments

Loss on equity method investments decreased $3.0 million as a result of our proportionate share of net loss from our equity method investments in the first nine months of 2018 compared to the first nine months of 2017.

Loss on Sale of Assets

During the first nine months of 2018, we recognized a net aggregate loss of $14.9 million primarily due to the sale of our Eagle Ford Shale assets, partially offset by a gain on the sale of oil and gas properties in east Texas. During the first nine months of 2017, we recognized a net aggregate loss of $13.5 million primarily due to the sale of our assets in West Virginia.

Interest Expense, net

Interest expense, net decreased $4.1 million due to $3.3 million lower interest expense resulting from the repayment of $237.0 million of our 6.51% weighted-average senior notes which matured in July 2018 and $4.0 million higher interest income partially offset by $3.8 million higher interest expense related to uncertain tax positions.

Other Expense (Income)

Other income decreased $5.3 million due to a lower curtailment gain on postretirement benefits as a result of the termination of approximately 100 employees in West Virginia in 2017.

Income Tax Expense

Income tax expense increased $5.2 million due to higher pre-tax income, partially offset by a lower effective tax rate. The effective tax rates for the first nine months of 2018 and 2017 were 24.4% and 37.2%, respectively. The decrease in the effective tax rate is primarily due to the impact of the Tax Cuts and Jobs Act law changes that were effective January 1, 2018, partially offset by an increase in the blended state statutory tax rate as a result of changes in our state apportionment factors due to the Eagle Ford Shale asset divestiture in February 2018.

Forward-Looking Information

The statements regarding future financial and operating performance and results, strategic pursuits and goals, market prices, future hedging and risk management activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words “expect,” “project,” “estimate,” “believe,” “anticipate,” “intend,” “budge “plan,” “forecast,” “target,” “predict,” “may,” “should,” “could,” “will” and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including geographic basis differentials) of natural gas and crude oil, results of future drilling and marketing activity, future production and costs, legislative and regulatory initiatives, electronic, cyber or physical security breaches and other factors detailed herein and in our other Securities and Exchange Commission filings. See “Risk Factors” in Item 1A of the Form 10-K/A for additional information about these risks and uncertainties. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

Market Risk

Our primary market risk is exposure to natural gas and crude oil prices. Realized prices are mainly driven by worldwide prices for crude oil and spot market prices for North American natural gas production. Commodity prices can be volatile and unpredictable.

Derivative Instruments and Risk Management Activities

Our risk management strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets through the use of commodity derivatives. A committee that consists of members of senior management

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oversees our risk management activities. Our commodity derivatives generally cover a portion of our production and provide only partial price protection by limiting the benefit to us of increases in prices, while protecting us in the event of price declines. Further, if any of our counterparties defaulted, this protection might be limited as we might not receive the full benefit of our commodity derivatives. Please read the discussion below as well as Note 6 of the Notes to the Consolidated Financial Statements in our Form 10-K/A for a more detailed discussion of our derivative and risk management activities.

Periodically, we enter into commodity derivatives including collar, swap and basis swap agreements, to protect against exposure to price declines related to our natural gas and crude oil production. Our credit agreement restricts our ability to enter into commodity derivatives other than to hedge or mitigate risks to which we have actual or projected exposure or as permitted under our risk management policies and not subjecting us to material speculative risks. All of our derivatives are used for risk management purposes and are not held for trading purposes. Under the collar agreements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. Under the swap agreements, we receive a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures.

As of September 30, 2018, we had the following outstanding financial commodity derivatives:

			Swaps	Basis Swaps	Estimated Fair Value
Type of Contract	Volume	Contract Period	Weighted-Average	Weighted-Average	Asset (Liability) (In thousands)
Natural gas (Leidy)	8.9 Bcf	Oct. 2018 - Dec. 2018		$ (0.69)	$ (2,195)
Natural gas (Leidy)	53.2 Bcf	Jan. 2019 - Dec. 2019		$ (0.55)	(1,787)
Natural gas (Transco)	13.3 Bcf	Oct. 2018 - Dec. 2019		$ 0.42	210
Natural gas (NYMEX)	23.2 Bcf	Oct. 2018 - Dec. 2018	$ 2.93		(4,709)
Natural gas (NYMEX)	1.5 Bcf	Oct. 2018	$ 3.10		(12)
					$ (8,493)

In the above table, natural gas prices are stated per Mcf.

The amounts set forth in the table above represent our total unrealized derivative position at September 30, 2018 and exclude the impact of non-performance risk. Non-performance risk is considered in the fair value of our derivative instruments that are recorded in our Condensed Consolidated Financial Statements and is primarily evaluated by reviewing credit default swap spreads for the various financial institutions with which we have derivative contracts, while our non-performance risk is evaluated using a market credit spread provided by one of our banks.

During the first nine months of 2018, natural gas basis swaps covered 33.0 Bcf, or 6%, of natural gas production at an average price of $2.56 per Mcf. Natural gas swaps covered 72.9 Bcf, or 14%, of natural gas production at an average price of $2.95 per Mcf. Crude oil collars with floor prices of $55.00 per Bbl and ceiling prices ranging from $63.35 to $63.80 per Bbl covered 0.2 Mmbbl, or 33%, of crude oil production at an average price of $63.62 per Bbl.

In January 2018, as a result of the pending sale of our Eagle Ford Shale assets, we terminated all of our outstanding crude oil financial derivatives for $0.3 million.

We are exposed to market risk on commodity derivative instruments to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Although notional contract amounts are used to express the volume of natural gas agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. Our counterparties are primarily commercial banks and financial service institutions that management believes present minimal credit risk and our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. We perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any losses related to non-performance risk of our counterparties and we do not anticipate any material impact on our financial results due to non-performance by third parties. However, we cannot be certain that we will not experience such losses in the future.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future commodity prices. See "Forward-Looking Information" for further details.

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Fair Value of Other Financial Instruments

The estimated fair value of other financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amount reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents approximates fair value due to the short-term maturities of these instruments.

We use available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount we would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our senior notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all senior notes and the revolving credit facility is based on interest rates currently available to us.

The carrying amount and fair value of debt is as follows:

	September 30, 2018		December 31, 2017	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$1,285,848	$1,245,971	$1,521,891	$1,527,624
Current maturities	(67,000)	(67,679)	(304,000)	(312,055)
Long-term debt, excluding current maturities	$1,218,848	$1,178,292	$1,217,891	$1,215,569

ITEM 4. Controls and Procedures

As of September 30, 2018, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the “Exchange Act”). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission’s rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

On January 1, 2018, the Company implemented a new Enterprise Resource Planning (ERP) system designed to upgrade our technology and improve our financial and operational information. The Company has modified its existing internal controls related to the ERP system implementation. While the Company believes that this new system and related changes to internal controls will ultimately strengthen its internal control over financial reporting, there are inherent risks in implementing a new ERP system and the Company will continue to evaluate and test these control changes in order to provide certification as of its fiscal year ending December 31, 2018 on the effectiveness, in all material respects, of its internal control over financial reporting.

With the exception of the ERP implementation described above, there were no changes in the Company's internal control over financial reporting that occurred during the third quarter of 2018 that have materially affected, or are reasonably likely to materially effect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

Legal Matters

The information set forth under the heading “Legal Matters” in Note 8 of the Notes to Condensed Consolidated Financial Statements included in Item 1 of Part I of this quarterly report is incorporated by reference in response to this item.

Environmental Matters

From time to time we receive notices of violation from governmental and regulatory authorities in areas in which we operate relating to alleged violations of environmental statutes or the rules and regulations promulgated thereunder. While we cannot predict with certainty whether these notices of violation will result in fines and/or penalties, if fines and/or penalties are imposed, they may result in monetary sanctions, individually or in the aggregate, in excess of $100,000.

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ITEM 1A. Risk Factors

For additional information about the risk factors that affect us, see Item 1A of Part I of our Annual Report on Form 10-K/A for the year ended December 31, 2017.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

Our Board of Directors has authorized a share repurchase program under which we may purchase shares of common stock in the open market or in negotiated transactions. In July 2018, the Board of Directors authorized an increase of 20.0 million shares to our share repurchase program. There is no expiration date associated with the authorization. The shares included in the table below were purchased on the open market and were held as treasury stock as of September 30, 2018.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
July 2018	—	$ —	—	30,080,295
August 2018	39,037	$ 22.87	39,037	30,041,258
September 2018[(1)]	7,131,508	$ 22.67	7,131,508	22,909,750
Total	7,170,545		7,170,545	

[(1)] Includes 2.7 million shares that were repurchased prior to September 30, 2018 and settled in October 2018.

Subsequent to September 30, 2018, we repurchased 2.8 million shares for a total cost of $65.6 million under a Rule 10b5-1 Plan.

ITEM 6. Exhibits

Exhibit Number	Description
31.1	302 Certification — Chairman, President and Chief Executive Officer.
31.2	302 Certification — Executive Vice President and Chief Financial Officer.
32.1	906 Certification.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

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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.

CABOT OIL & GAS CORPORATION
(Registrant)

October 26, 2018	By:	/s/ DAN O. DINGES
		Dan O. Dinges
		Chairman, President and Chief Executive Officer
		(Principal Executive Officer)
October 26, 2018	By:	/s/ SCOTT C. SCHROEDER
		Scott C. Schroeder
		Executive Vice President and Chief Financial Officer
		(Principal Financial Officer)
October 26, 2018	By:	/s/ TODD M. ROEMER
		Todd M. Roemer
		Vice President and Controller
		(Principal Accounting Officer)