QEP RESOURCES, INC.
Form 10-Q
July 25, 2018

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 June 30, 2018

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

For the transition period from _____ to _____

Commission File Number: 001-34778
QEP RESOURCES, INC.

(Exact name of registrant as specified in its charter)

STATE OF DELAWARE	87-0287750
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1050 17th Street, Suite 800, Denver, Colorado 80265
(Address of principal executive offices)

Registrant's telephone number, including area code (303) 672-6900

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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:

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

Emerging growth company o

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

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

At June 30, 2018, there were 236,975,957 shares of the registrant's common stock, $0.01 par value, outstanding.

QEP Resources, Inc.
Form 10-Q for the Quarter Ended June 30, 2018

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS
QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions, except per share amounts)			
REVENUES				
Oil and condensate, gas and NGL sales	$520.3	$373.0	$930.1	$758.2
Other revenue	3.0	2.7	8.0	6.7
Purchased oil and gas sales	9.1	8.0	23.2	38.9
Total Revenues	532.4	383.7	961.3	803.8
OPERATING EXPENSES				
Purchased oil and gas expense	9.8	9.1	25.3	38.5
Lease operating expense	66.5	70.0	139.0	139.2
Transportation and processing costs	31.2	72.2	65.2	142.4
Gathering and other expense	3.4	1.8	6.2	3.3
General and administrative	55.8	31.3	115.9	64.9
Production and property taxes	37.6	28.5	66.5	57.6
Depreciation, depletion and amortization	242.2	191.5	438.7	383.3
Exploration expenses	0.1	—	0.1	0.4
Impairment	403.7	—	404.4	0.1
Total Operating Expenses	850.3	404.4	1,261.3	829.7
Net gain (loss) from asset sales, inclusive of restructuring costs	(3.9)	19.8	(0.4)	19.8
OPERATING INCOME (LOSS)	(321.8)	(0.9)	(300.4)	(6.1)
Realized and unrealized gains (losses) on derivative contracts (Note 7)	(79.1)	106.7	(132.3)	267.6
Interest and other income (expense)	(3.1)	1.8	(3.8)	2.4
Interest expense	(38.2)	(34.9)	(73.2)	(68.7)
INCOME (LOSS) BEFORE INCOME TAXES	(442.2)	72.7	(509.7)	195.2
Income tax (provision) benefit	106.2	(27.3)	120.1	(72.9)
NET INCOME (LOSS)	$(336.0)	$45.4	$(389.6)	$122.3
Earnings (loss) per common share				
Basic	$(1.42)	$0.19	$(1.63)	$0.51
Diluted	$(1.42)	$0.19	$(1.63)	$0.51
Weighted-average common shares outstanding				
Used in basic calculation	237.0	240.5	238.9	240.4
Used in diluted calculation	237.0	240.6	238.9	240.5
Dividends per common share	$—	$—	$—	$—

Refer to Notes accompanying the Condensed Consolidated Financial Statements.

QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Net income (loss)	$(336.0)	$45.4	$(389.6)	$122.3
Other comprehensive income, net of tax:				
Postretirement medical plan change[1]	—	—	—	1.6
Fair value of plan assets adjustment[2]	—	—	0.3	—
Pension and other postretirement plans adjustments:				
Amortization of prior service costs[3]	0.1	0.2	0.2	0.3
Amortization of actuarial losses[4]	0.2	(0.1)	0.4	0.1
Other comprehensive income	0.3	0.1	0.9	2.0
Comprehensive income (loss)	$(335.7)	$45.5	$(388.7)	$124.3

(1) Presented net of income tax expense of $1.0 million for the six months ended June 30, 2017.

(2) Adjustment recorded during the six months ended June 30, 2018, related to a change in the fair value of plan assets as of December 31, 2017.

(3) Presented net of income tax expense of $0.1 million and $0.1 million for the three and six months ended June 30, 2018, respectively. Presented net of income tax expense of $0.1 million and $0.2 million for the three and six months ended June 30, 2017, respectively.

(4) Presented net of income tax expense of $0.1 million and $0.2 million for the three and six months ended June 30, 2018, respectively. Presented net of income tax expense of $0.1 million for the six months ended June 30, 2017.

Refer to Notes accompanying the Condensed Consolidated Financial Statements.

QEP RESOURCES, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2018	December 31, 2017
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	$—	$ —
Accounts receivable, net	175.0	141.8
Income tax receivable	5.3	4.9
Fair value of derivative contracts	23.7	3.4
Prepaid expenses	9.8	10.1
Other current assets	0.3	4.3
Total Current Assets	214.1	164.5
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	12,852.3	11,873.6
Unproved properties	1,041.0	1,086.4
Gathering and other	359.7	318.7
Materials and supplies	32.2	32.9
Total Property, Plant and Equipment	14,285.2	13,311.6
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	7,267.1	6,642.9
Gathering and other	116.2	124.3
Total Accumulated Depreciation, Depletion and Amortization	7,383.3	6,767.2
Net Property, Plant and Equipment	6,901.9	6,544.4
Fair value of derivative contracts	5.4	0.1
Other noncurrent assets	56.5	53.0
Noncurrent assets held for sale	211.8	632.8
TOTAL ASSETS	$7,389.7	$ 7,394.8
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	$8.5	$ 44.0
Accounts payable and accrued expenses	388.0	363.8
Production and property taxes	36.3	31.6
Interest payable	32.7	26.0
Fair value of derivative contracts	155.2	103.6
Asset retirement obligations	6.0	3.5
Total Current Liabilities	626.7	572.5
Long-term debt	2,649.4	2,160.8
Deferred income taxes	397.7	518.0
Asset retirement obligations	154.6	159.0
Fair value of derivative contracts	49.3	31.8
Other long-term liabilities	97.8	102.2
Other long-term liabilities held for sale	52.8	52.6
Commitments and contingencies (Note 10)		
EQUITY		
Common stock – par value $0.01 per share; 500.0 million shares authorized; 239.7 million and 243.0 million shares issued, respectively	2.4	2.4
Treasury stock – 2.7 million and 2.0 million shares, respectively	(41.2)	(34.2)

Additional paid-in capital	1,415.7	1,398.2
Retained earnings	1,994.7	2,442.6
Accumulated other comprehensive income (loss)	(10.2)	(11.1)
Total Common Shareholders' Equity	3,361.4	3,797.9
TOTAL LIABILITIES AND EQUITY	$7,389.7	$ 7,394.8

Refer to Notes accompanying the Condensed Consolidated Financial Statements.

QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENT OF EQUITY
(Unaudited)

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income(Loss)	Total
	Shares	Amount	Shares	Amount				
	(in millions)							
Balance at December 31, 2017	243.0	$ 2.4	(2.0)	$(34.2)	$1,398.2	$2,442.6	$ (11.1)	$3,797.9
Net income (loss)	—	—	—	—	—	(389.6)	—	(389.6)
Common stock repurchased and retired	(6.2)	(0.1)	—	—	—	(58.3)	—	(58.4)
Share-based compensation	2.9	0.1	(0.7)	(7.0)	17.5	—	—	10.6
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	0.9	0.9
Balance at June 30, 2018	239.7	$ 2.4	(2.7)	$(41.2)	$1,415.7	$1,994.7	$ (10.2)	$3,361.4

Refer to Notes accompanying the Condensed Consolidated Financial Statements.

QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2018	2017
OPERATING ACTIVITIES	(in millions)	
Net income (loss)	$(389.6)	$122.3
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	438.7	383.3
Deferred income taxes (benefit)	(120.5)	67.2
Impairment	404.4	0.1
Share-based compensation	23.4	7.7
Amortization of debt issuance costs and discounts	2.6	3.1
Bargain purchase gain from acquisition	—	0.4
Net (gain) loss from asset sales, inclusive of restructuring costs	0.4	(19.8)
Unrealized (gains) losses on marketable securities	(0.4)	(1.4)
Unrealized (gains) losses on derivative contracts	43.6	(277.6)
Changes in operating assets and liabilities	(25.7)	10.7
Net Cash Provided by (Used in) Operating Activities	376.9	296.0
INVESTING ACTIVITIES		
Property acquisitions	(45.1)	(76.6)
Property, plant and equipment, including exploratory well expense	(764.3)	(477.9)
Proceeds from disposition of assets	48.8	2.3
Net Cash Provided by (Used in) Investing Activities	(760.6)	(552.2)
FINANCING ACTIVITIES		
Checks outstanding in excess of cash balances	(35.5)	(0.5)
Long-term debt issuance costs paid	—	(1.1)
Proceeds from credit facility	2,029.5	—
Repayments of credit facility	(1,543.5)	—
Common stock repurchased and retired	(58.4)	—
Treasury stock repurchases	(5.9)	(6.4)
Other capital contributions	0.2	—
Net Cash Provided by (Used in) Financing Activities	386.4	(8.0)
Change in cash, cash equivalents and restricted cash	2.7	(264.2)
Beginning cash, cash equivalents and restricted cash[1]	23.4	465.4
Ending cash, cash equivalents and restricted cash[1]	$26.1	$201.2
Supplemental Disclosures:		
Cash paid for interest, net of capitalized interest	$63.5	$64.3
Cash paid for income taxes, net	$0.2	$—
Non-cash Investing Activities:		
Change in capital expenditure accruals and other non-cash adjustments	$20.2	$42.4

[1] Refer to New Accounting Pronouncements in Note 1 – Basis of Presentation.

Refer to Notes accompanying the Condensed Consolidated Financial Statements.

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QEP RESOURCES, INC.
NOTES ACCOMPANYING THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 – Basis of Presentation

Nature of Business

QEP Resources, Inc. is an independent crude oil and natural gas exploration and production company with operations in two regions of the United States: the Southern Region (primarily in Texas and Louisiana) and the Northern Region (primarily in North Dakota and Utah). Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its subsidiaries on a consolidated basis. QEP's corporate headquarters are located in Denver, Colorado and shares of QEP's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "QEP".

Basis of Presentation of Interim Condensed Consolidated Financial Statements

The interim Condensed Consolidated Financial Statements contain the accounts of QEP and its majority-owned or controlled subsidiaries. The Condensed Consolidated Financial Statements were prepared in accordance with Generally Accepted Accounting Principles (GAAP) in the United States and with the instructions for Quarterly Reports on Form 10-Q and Regulation S-X. All significant intercompany accounts and transactions have been eliminated in consolidation.

The Condensed Consolidated Financial Statements reflect all normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair statement of financial position and results of operations for the interim periods presented. Interim Condensed Consolidated Financial Statements and the year-end balance sheet do not include all of the information and notes required by GAAP for audited annual consolidated financial statements. These Condensed Consolidated Financial Statements should be read in conjunction with the Consolidated Financial Statements and Notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2017.

The preparation of the Condensed Consolidated Financial Statements and Notes in conformity with GAAP requires that management make estimates and assumptions that affect revenues, expenses, assets and liabilities, and disclosure of contingent assets and liabilities. Actual results could differ from estimates. The results of operations for the three and six months ended June 30, 2018, are not necessarily indicative of the results that may be expected for the year ending December 31, 2018.

Reclassifications

Certain prior period balances on the Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Cash Flows have been reclassified due to noncurrent held for sale classification related to the signing of a purchase and sale agreement associated with the pending divestiture of the Uinta Basin assets and to conform to the current year presentation. Such reclassifications had no effect on the Company's net income (loss), earnings (loss) per share or retained earnings previously reported.

Impairment of Long-Lived Assets

During the six months ended June 30, 2018, QEP recorded impairment charges of $404.4 million, of which $402.8 million of proved and unproved properties impairment was triggered due to the signing of a purchase and sale

agreement for the divestiture of the Uinta Basin assets. Additionally, QEP recorded $1.6 million related to expiring leaseholds on unproved properties and impairment of proved properties for a divestiture in the Other Northern area.

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist principally of highly liquid investments in securities with original maturities of three months or less made through commercial bank accounts that result in available funds the next business day. Restricted cash are funds that are legally or contractually reserved for a specific purpose and therefore not available for immediate or general business use.

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the Condensed Consolidated Balance Sheets to the amounts shown in the Condensed Consolidated Statements of Cash Flows:

	June 30,	
	2018	2017
	(in millions)	
Cash and cash equivalents	$—	$178.8
Restricted cash[1]	26.1	22.4
Total cash, cash equivalents and restricted cash shown in the Condensed Consolidated Statements of Cash Flows	$26.1	$201.2

(1) As of June 30, 2018, the restricted cash balance consisted of $26.1 million included within "Other noncurrent assets" on the Condensed Consolidated Balance Sheet. As of June 30, 2017, the restricted cash balance consisted of $22.4 million included within "Other noncurrent assets" on the Condensed Consolidated Balance Sheet provided within the Quarterly Report on Form 10-Q. QEP's restricted cash is primarily cash deposited into an escrow account related to a title dispute between third parties in the Williston Basin.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (Topic 606), which seeks to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when revenue is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. In addition, new and enhanced disclosures are required. The amendment was effective prospectively for reporting periods beginning on or after December 15, 2017, and early adoption was permitted for periods beginning on or after December 15, 2016. The two permitted transition methods under the new standard are the full retrospective method, in which case the standard would be applied to each prior reporting period presented, or the modified retrospective method, in which case the cumulative effect of applying the standard would be recognized at the date of initial application. The Company has selected the modified retrospective method and adopted this standard in the first quarter of 2018. Refer to Note 2 – Revenue for more information.

In conjunction with ASU No. 2014-09, in March 2016, the FASB issued ASU No. 2016-08, Revenue from contracts with customers (Topic 606): Principal versus agent considerations (reporting revenue gross versus net), which clarifies the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued ASU No. 2016-10, Revenue from contracts with customers (Topic 606): Identifying performance obligations and licensing, which clarifies guidance related to identifying performance obligations and licensing implementation guidance contained in the new revenue recognition standard. In May 2016, the FASB issued ASU No. 2016-11, Revenue recognition (Topic 605) and Derivatives and hedging (Topic 815): Rescission of SEC guidance because of ASU 2014-09 and 2014-16, which rescinds certain SEC staff observer comments that are codified in Topic 605, Revenue Recognition. In May 2016, the FASB issued ASU No. 2016-12, Revenue from contracts with customers (Topic 606): Narrow-scope improvements and practical expedients, which intends to reduce the cost and complexity of applying the new revenue standard by narrowing the scope of improvements to the guidance on collectability, non-cash consideration, and completed contracts at transition. In December 2016, the FASB issued ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers, which intends to make corrections or improvements to the FASB Accounting Standards Codification which includes guidance and

reference clarification, simplification and minor improvements. These amendments were effective prospectively for reporting periods beginning on or after December 31, 2017, and early adoption was permitted for periods beginning on or after December 31, 2016. The Company adopted these ASUs in the first quarter of 2018. Refer to Note 2 – Revenue for more information.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which requires lessees to recognize the lease assets and lease liabilities classified as operating leases on the balance sheet and disclosing key quantitative and qualitative information about leasing arrangements. The amendment will be effective for reporting periods beginning on or after December 15, 2018, and early adoption is permitted. QEP does not plan to early adopt this new standard. This standard does not apply to leases to explore for or use minerals, oil or natural gas resources, including the right to explore for those natural resources. QEP believes this new guidance will likely increase the recorded asset and liability balances on the Company's Condensed Consolidated Balance Sheets due to the required recognition of right-of-use assets and corresponding lease liabilities, but has not determined the aggregate amount of change.

In October 2016, the FASB issued ASU No. 2016-16, Accounting for Income Taxes: Intra-Entity Asset Transfers of Assets Other than Inventory, which intends to reduce the complexity in accounting standards related to intra-entity asset transfers by requiring a reporting entity to recognize the tax effects from the sale of assets when a transfer occurs, even though the pre-tax effects of the transaction are eliminated in consolidation. This amendment was effective retrospectively for reporting periods beginning after December 15, 2017, and early adoption was permitted. The Company adopted this standard in the first quarter of 2018 and the adoption did not have a material impact on the Company's Condensed Consolidated Financial Statements.

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted cash, which intends to clarify how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. This amendment was effective retrospectively for reporting periods after December 15, 2017, and early adoption was permitted. The Company adopted this standard in the first quarter of 2018 and the adoption did not have a material impact on the Company's Condensed Consolidated Statements of Cash Flows.

In February 2018, the FASB issued ASU No. 2018-02, Income statement - Reporting comprehensive income (Topic 220) - Reclassification of certain tax effects from accumulated other comprehensive income, which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. The amendment will be effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. The Company is currently assessing the impact of the ASU on the Company's Condensed Consolidated Financial Statements.

In March 2018, the FASB issued ASU No. 2018-05, Income Taxes (Topic 740) - Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118, which amends guidance on certain investments and income taxes as a result of the Tax Cuts and Jobs Act of 2017. The amendment is effective upon issuance. The adoption did not have a material impact on the Company's Condensed Consolidated Financial Statements.

Note 2 – Revenue

Adoption of ASC Topic 606, Revenue from Contracts with Customers

On January 1, 2018, QEP adopted ASC Topic 606, Revenue from Contracts with Customers, using the modified retrospective approach, which was applied to those contracts which were not completed as of January 1, 2018. Results for reporting periods beginning January 1, 2018, are presented in accordance with ASC Topic 606, while prior period amounts are reported in accordance with ASC Topic 605, Revenue Recognition.

In accordance with ASC Topic 606, QEP now records transportation and processing costs that are incurred after control of its product has transferred to the customer as a reduction of "Oil and condensate, gas and NGL sales" on the Condensed Consolidated Statements of Operations. Prior to the adoption of ASC Topic 606, these transportation and processing costs were recorded as an expense within "Transportation and processing costs" on the Condensed Consolidated Statements of Operations. There was no impact to net income (loss) or opening retained earnings as a

result of adopting ASC Topic 606.

The following table presents the impact to the Condensed Consolidated Statements of Operations as a result of adopting ASC Topic 606.

	Three Months Ended June 30, 2018			Six Months Ended June 30, 2018		
	As Reported	ASC Topic 606 Adjustments	As Adjusted[1]	As Reported	ASC Topic 606 Adjustments	As Adjusted[1]
REVENUES	(in millions, except per share amounts)					
Oil and condensate, gas and NGL sales	$520.3	$ 12.4	$ 532.7	$930.1	$ 25.1	$ 955.2
Other revenue	3.0	—	3.0	8.0	—	8.0
Purchased oil and gas sales	9.1	—	9.1	23.2	—	23.2
Total Revenues	532.4	12.4	544.8	961.3	25.1	986.4
OPERATING EXPENSES						
Purchased oil and gas expense	9.8	—	9.8	25.3	—	25.3
Lease operating expense	66.5	—	66.5	139.0	—	139.0
Transportation and processing costs	31.2	12.4	43.6	65.2	25.1	90.3
Gathering and other expense	3.4	—	3.4	6.2	—	6.2
General and administrative	55.8	—	55.8	115.9	—	115.9
Production and property taxes	37.6	—	37.6	66.5	—	66.5
Depreciation, depletion and amortization	242.2	—	242.2	438.7	—	438.7
Exploration expenses	0.1	—	0.1	0.1	—	0.1
Impairment	403.7	—	403.7	404.4	—	404.4
Total Operating Expenses	850.3	12.4	862.7	1,261.3	25.1	1,286.4
Net gain (loss) from asset sales, inclusive of restructuring costs	(3.9)	—	(3.9)	(0.4)	—	(0.4)
OPERATING INCOME (LOSS)	(321.8)	—	(321.8)	(300.4)	—	(300.4)
Realized and unrealized gains (losses) on derivative contracts (Note 7)	(79.1)	—	(79.1)	(132.3)	—	(132.3)
Interest and other income (expense)	(3.1)	—	(3.1)	(3.8)	—	(3.8)
Interest expense	(38.2)	—	(38.2)	(73.2)	—	(73.2)
INCOME (LOSS) BEFORE INCOME TAXES	(442.2)	—	(442.2)	(509.7)	—	(509.7)
Income tax (provision) benefit	106.2	—	106.2	120.1	—	120.1
NET INCOME (LOSS)	$(336.0)	$ —	$ (336.0)	$(389.6)	$ —	$ (389.6)
Earnings (loss) per common share						
Basic	$(1.42)	$ —	$ (1.42)	$(1.63)	$ —	$ (1.63)
Diluted	$(1.42)	$ —	$ (1.42)	$(1.63)	$ —	$ (1.63)
Weighted-average common shares outstanding						
Used in basic calculation	237.0	—	237.0	238.9	—	238.9
Used in diluted calculation	237.0	—	237.0	238.9	—	238.9
Dividends per common share	$—	$ —	$ —	$—	$ —	$ —

(1) This column excludes the impact of adopting ASC Topic 606 and is consistent with the presentation prior to January 1, 2018.

Revenue Recognition

QEP recognizes revenue from the sales of oil and condensate, gas and NGL in the period that the performance obligations are satisfied. QEP's performance obligations are satisfied when the customer obtains control of product, when we have no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sales of oil and condensate, gas and NGL are made under contracts with customers, which typically include consideration that is based on pricing tied to local indices and volumes delivered in the current month. Reported revenues include estimates for the two most recent months using published commodity price indexes and volumes supplied by field operators. Performance obligations under our contracts with customers are typically satisfied at a point in time through monthly delivery of oil and condensate, gas and/or NGL. Our contracts with customers typically require payment for oil and condensate, gas and NGL sales within 30 days following the calendar month of delivery.

QEP's oil is typically sold at specific delivery points under contract terms that are common in our industry. QEP's gas and NGL are also sold under contract types that are common in our industry; however, under these contracts, the gas and its components, including NGL, may be sold to a single purchaser or the residue gas and NGL may be sold to separate purchasers. Regardless of the contract type, the terms of these contracts compensate the Company for the value of the residue gas and NGL constituent components at market prices for each product. QEP also purchases and resells oil and gas primarily to mitigate losses on unutilized capacity related to firm transportation commitments and storage activities. QEP recognizes revenue from these resale activities in the period that the performance obligations are satisfied. A wellhead imbalance liability is recorded to the extent that QEP has sold volumes in excess of its share of remaining reserves in an underlying property.

The following tables present our revenues that are disaggregated by revenue source and by geographic area. Transportation and processing costs in the following tables are not all of the transportation and processing costs that the Company incurs, only the expenses that are netted against revenues pursuant to ASC Topic 606.

	Oil and condensate sales	Gas sales	NGL sales	Transportation and processing costs included in revenue	Oil and condensate, gas and NGL sales, as reported
	(in millions)				
	Three Months Ended June 30, 2018				
Northern Region					
Williston Basin	$207.6	$8.4	$14.7	$ (10.7)	$ 220.0
Uinta Basin	9.5	7.9	1.7	—	19.1
Other Northern	0.9	0.2	0.1	—	1.2
Southern Region					
Permian Basin	190.3	3.2	9.9	(1.7)	201.7
Haynesville/Cotton Valley	0.2	77.9	—	—	78.1
Other Southern	—	0.2	—	—	0.2
Total oil and condensate, gas and NGL sales	$408.5	$97.8	$26.4	$ (12.4)	$ 520.3
	Three Months Ended June 30, 2017[1]				
Northern Region					
Williston Basin	$135.4	$11.0	$9.3	$ —	$ 155.7
Pinedale	6.0	51.2	8.4	—	65.6
Uinta Basin	6.9	12.3	1.1	—	20.3
Other Northern	1.4	4.9	0.1	—	6.4
Southern Region					
Permian Basin	66.0	3.6	3.8	—	73.4
Haynesville/Cotton Valley	0.2	51.0	0.1	—	51.3
Other Southern	0.1	0.2	—	—	0.3
Total oil and condensate, gas and NGL sales	$216.0	$134.2	$22.8	$ —	$ 373.0

[1] Prior period amounts have not been adjusted under the modified retrospective method.

	Oil and condensate sales	Gas sales	NGL sales	Transportation and processing costs included in revenue	Oil and condensate, gas and NGL sales, as reported
	(in millions)				
	Six Months Ended June 30, 2018				
Northern Region					
Williston Basin	$368.1	$18.2	$26.5	$ (20.6)	$ 392.2
Uinta Basin	17.9	18.0	3.4	—	39.3
Other Northern	2.8	1.2	(0.1)	—	3.9
Southern Region					
Permian Basin	320.1	7.8	16.4	(4.5)	339.8
Haynesville/Cotton Valley	0.6	154.3	—	—	154.9
Other Southern	(0.3)	0.3	—	—	—
Total oil and condensate, gas and NGL sales	$709.2	$199.8	$46.2	$ (25.1)	$ 930.1
	Six Months Ended June 30, 2017[1]				
Northern Region					
Williston Basin	$290.8	$23.0	$21.8	$ —	$ 335.6
Pinedale	12.8	111.8	20.0	—	144.6
Uinta Basin	14.3	26.9	2.7	—	43.9
Other Northern	2.8	10.8	0.2	—	13.8
Southern Region					
Permian Basin	116.2	6.8	6.9	—	129.9
Haynesville/Cotton Valley	0.6	89.2	0.2	—	90.0
Other Southern	0.2	0.2	—	—	0.4
Total oil and condensate, gas and NGL sales	$437.7	$268.7	$51.8	$ —	$ 758.2

[1] Prior period amounts have not been adjusted under the modified retrospective method.

Note 3 – Acquisitions and Divestitures

Acquisitions

During the six months ended June 30, 2018, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage in the Permian Basin for an aggregate purchase price of $45.1 million, subject to post-closing purchase price adjustments. Of the $45.1 million, $37.5 million was related to acquisitions from various persons who owned additional oil and gas interests in certain properties included in the 2017 acquisition of oil and gas properties in the Permian Basin (the 2017 Permian Basin Acquisition) on substantially the same terms and conditions as the 2017 Permian Basin Acquisition in the fourth quarter of 2017.

During the six months ended June 30, 2017, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage and additional surface acreage in the Permian Basin, for an aggregate purchase price of $76.6 million. In conjunction with these acquisitions, the Company recorded $5.3 million of goodwill, which was subsequently impaired in 2017.

Divestitures

In February 2018, QEP's Board of Directors unanimously approved certain strategic and financial initiatives (Strategic Initiatives) including plans to market its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley and focus its activities in the Permian Basin. As a part of this process, the Company engaged advisors to assist with the divestitures of its Williston Basin and Uinta Basin assets and provided data for potential buyers to evaluate. The assets will be considered held for sale once it is deemed unlikely that there will be any significant changes to QEP's divestiture plan, which QEP believes is generally upon the execution of purchase and sale agreements.

Uinta Basin Divestiture

On July 5, 2018, the Company's wholly owned subsidiary, QEP Energy Company, entered into a definitive agreement to sell natural gas and oil producing properties, undeveloped acreage and related assets located in the Uinta Basin for proceeds of $155.0 million, subject to customary purchase price adjustments (the Uinta Basin Divestiture). The transaction is expected to close in September 2018. Since the transaction was substantially finalized at June 30, 2018, the assets and liabilities associated with the Uinta Basin Divestiture have been classified as noncurrent assets and liabilities held for sale on the Condensed Consolidated Balance Sheets and the notes accompanying the Condensed Consolidated Financial Statements. Pursuant to signing a purchase and sale agreement for the Uinta Basin Divestiture, QEP recorded $402.8 million of proved and unproved properties impairment during the three and six months ended June 30, 2018 (refer to Note 1 – Basis of Presentation for more information). In addition, QEP recorded $1.9 million of estimated restructuring costs related to this divestiture during the three and six months ended June 30, 2018, included in "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Condensed Consolidated Statements of Operations (refer to Note 8 – Restructuring for more information).

The following table presents the carrying amounts of the major classes of assets and liabilities classified as noncurrent assets and liabilities held for sale on the Condensed Consolidated Balance Sheets:

	June 30, 2018	December 31, 2017
	(in millions)	
Assets		
Current assets, total	$0.4	$ 0.9
Property, Plant and Equipment	192.5	612.6
Other noncurrent assets	18.9	19.3
Noncurrent assets held for sale	$211.8	$ 632.8
Liabilities		
Current liabilities, total	$0.9	$ 0.8
Asset retirement obligations, current	3.5	4.0
Asset retirement obligations, long-term	48.2	47.6
Other long-term liabilities	0.2	0.2
Other long-term liabilities held for sale	$52.8	$ 52.6

Pinedale Divestiture

In September 2017, QEP sold its assets in Pinedale (the Pinedale Divestiture), for net cash proceeds of $718.2 million. For the six months ended June 30, 2018, QEP recorded a pre-tax gain on sale of $0.8 million, due to additional post-closing purchase price adjustments, which were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Condensed Consolidated Statements of Operations. For the three and six months ended June 30, 2017, QEP had net income before income taxes related to the divested Pinedale properties of $15.0 million and $43.0 million, respectively.

As a part of the Pinedale Divestiture, QEP agreed to reimburse the buyer for certain deficiency charges it incurs related to gas processing and NGL transportation and fractionation contracts between the effective date of the sale and December 31, 2019, in an aggregate amount not to exceed $45.0 million. As of June 30, 2018, the remaining liability associated with estimated future payments for this commitment was $23.8 million, which is reported on the Condensed Consolidated Balance Sheets within "Accounts payable and accrued expenses".

Other Divestitures

During the six months ended June 30, 2018, QEP received net cash proceeds of $48.8 million and recorded a net pre-tax gain of $0.7 million related to the divestiture of properties outside our main operating areas in the Uinta Basin, Pinedale and Other Northern area, and the sale of an underground gas storage facility.

During the six months ended June 30, 2017, QEP received proceeds of $2.3 million and recorded accounts receivable of $36.7 million, resulting in a pre-tax gain on sale of $19.8 million, primarily related to the divestiture of certain non-core properties in the Other Northern area.

The gains and losses were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Condensed Consolidated Statements of Operations.

Note 4 – Earnings Per Share

Basic earnings per share (EPS) are computed by dividing net income (loss) by the weighted-average number of common shares outstanding during the reporting period. Diluted EPS includes the potential increase in the number of outstanding shares that could result from the exercise of in-the-money stock options. QEP's unvested restricted share awards are included in weighted-average basic common shares outstanding because, once the shares are granted, the restricted share awards are considered issued and outstanding, the historical forfeiture rate is minimal and the restricted share awards are eligible to receive dividends.

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are considered participating securities and are included in the computation of earnings (loss) per share pursuant to the two-class method. The Company's unvested restricted share awards contain non-forfeitable dividend rights and participate equally with common stock with respect to dividends issued or declared. However, the Company's unvested restricted share awards do not have a contractual obligation to share in losses of the Company. The Company's unexercised stock options do not contain rights to dividends. Under the two-class method, the earnings used to determine basic earnings per common share are reduced by an amount allocated to participating securities. When the Company records a net loss, none of the loss is allocated to the participating securities since the securities are not obligated to share in Company losses. Use of the two-class method has an insignificant impact on the calculation of basic and diluted earnings (loss) per common share. During the three and six months ended June 30, 2018, 0.1 million shares were not included in diluted common shares outstanding as they were anti-dilutive to QEP's net loss. During the three and six months ended June 30, 2017, there were no anti-dilutive shares.

The following is a reconciliation of the components of basic and diluted shares used in the EPS calculation:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			

Weighted-average basic common shares outstanding	237.0	240.5	238.9	240.4
Potential number of shares issuable upon exercise of in-the-money stock options under the Long-Term Stock Incentive Plan	—	0.1	—	0.1
Average diluted common shares outstanding	237.0	240.6	238.9	240.5

Note 5 – Asset Retirement Obligations

QEP records asset retirement obligations (ARO) associated with the retirement of tangible, long-lived assets. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar assets and depreciated over the life of the related assets. Revisions to the ARO estimates result from changes in expected cash flows or material changes in estimated asset retirement costs. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. Of the $160.6 million and $162.5 million ARO liability for the periods ended June 30, 2018 and December 31, 2017, respectively, $6.0 million and $3.5 million, respectively, were included as a current liability within "Asset retirement obligations" on the Condensed Consolidated Balance Sheets.

The following is a reconciliation of the changes in the Company's ARO for the period specified below:

	Asset Retirement Obligations (in millions)
ARO liability at December 31, 2017[1]	$ 162.5
Accretion	2.6
Additions	3.5
Revisions	(3.5)
Liabilities settled	(4.5)
ARO liability at June 30, 2018[1]	$ 160.6

(1) Excludes $51.6 million of ARO classified as "Other long-term liabilities held for sale" on the Condensed Consolidated Balance Sheets related to the Uinta Basin Divestiture as of both June 30, 2018 and December 31, 2017.

Note 6 – Fair Value Measurements

QEP measures and discloses fair values in accordance with the provisions of ASC 820, Fair Value Measurements and Disclosures. This guidance defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair value measurements. ASC 820 also establishes a fair value hierarchy. Level 1 inputs are quoted prices (unadjusted) for identical assets or liabilities in active markets that the Company has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability.

QEP has determined that its commodity derivative instruments are Level 2. The Level 2 fair value of commodity derivative contracts (refer to Note 7 – Derivative Contracts) is based on market prices posted on the respective commodity exchange on the last trading day of the reporting period and industry standard discounted cash flow models. QEP primarily applies the market approach for recurring fair value measurements and maximizes its use of observable inputs and minimizes its use of unobservable inputs. QEP considers bid and ask prices for valuing the majority of its assets and liabilities measured and reported at fair value. In addition to using market data, QEP makes assumptions in valuing its assets and liabilities, including assumptions about risk and the risks inherent in the inputs to the valuation technique. The Company's policy is to recognize significant transfers between levels at the end of the reporting period.

Certain of the Company's commodity derivative instruments are valued using industry standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable prices at which transactions are executed in the marketplace. The determination of fair value for derivative assets and liabilities also incorporates nonperformance risk for counterparties and for QEP. Derivative contract fair values are reported on a net basis to the extent a legal right of offset with the counterparty exists.

The fair value of financial assets and liabilities at June 30, 2018 and December 31, 2017, is shown in the table below:

	Fair Value Measurements				
	Gross Amounts of Assets and Liabilities			Netting Adjustments[1]	Net Amounts Presented on the Condensed Consolidated Balance Sheets
	Level 1	Level 2	Level 3		
	June 30, 2018				
Financial Assets	(in millions)				
Fair value of derivative contracts – short-term	$—	$28.0	$—	$ (4.3)	$ 23.7
Fair value of derivative contracts – long-term	—	7.3	—	(1.9)	5.4
Total financial assets	$—	$35.3	$—	$ (6.2)	$ 29.1
Financial Liabilities					
Fair value of derivative contracts – short-term	$—	$159.5	$—	$ (4.3)	$ 155.2
Fair value of derivative contracts – long-term	—	51.2	—	(1.9)	49.3
Total financial liabilities	$—	$210.7	$—	$ (6.2)	$ 204.5
	December 31, 2017				
Financial Assets					
Fair value of derivative contracts – short-term	$—	$20.6	$—	$ (17.2)	$ 3.4
Fair value of derivative contracts – long-term	—	2.3	—	(2.2)	0.1
Total financial assets	$—	$22.9	$—	$ (19.4)	$ 3.5
Financial Liabilities					
Fair value of derivative contracts – short-term	$—	$120.8	$—	$ (17.2)	$ 103.6
Fair value of derivative contracts – long-term	—	34.0	—	(2.2)	31.8
Total financial liabilities	$—	$154.8	$—	$ (19.4)	$ 135.4

(1) The Company nets its derivative contract assets and liabilities outstanding with the same counterparty on the Condensed Consolidated Balance Sheets, for the contracts that contain netting provisions. Refer to Note 7 – Derivative Contracts for additional information regarding the Company's derivative contracts.

The following table discloses the fair value and related carrying amount of certain financial instruments not disclosed in other Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q:

	Carrying Amount	Level 1 Fair Value	Carrying Amount	Level 1 Fair Value
	June 30, 2018		December 31, 2017	
Financial Assets	(in millions)			
Cash and cash equivalents	$—	$—	$—	$—
Financial Liabilities				
Checks outstanding in excess of cash balances	$8.5	$8.5	$44.0	$44.0
Long-term debt	$2,649.4	$2,684.2	$2,160.8	$2,256.2

The carrying amounts of cash and cash equivalents and checks outstanding in excess of cash balances approximate fair value. The fair value of fixed-rate long-term debt is based on the trading levels and dollar prices for the Company's debt at the end of the quarter.

The fair value of the deficiency charge obligation associated with the Pinedale Divestiture was measured utilizing an internally developed cash flow model discounted at QEP's weighted average cost of debt. Given the unobservable nature of the inputs, the fair value calculation associated with the deficiency charges is considered Level 3 within the fair value hierarchy. Refer to Note 3 – Acquisitions and Divestitures for additional information.

The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and is based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of ARO includes plugging costs and reserve lives. A reconciliation of the Company's ARO is presented in Note 5 – Asset Retirement Obligations.

Nonrecurring Fair Value Measurements

The provisions of the fair value measurement standard are also applied to the Company's nonrecurring measurements. The Company utilizes fair value on a periodic basis to review its proved oil and gas properties for potential impairment when events and changes in circumstances indicate that the carrying amount of such property may not be recoverable. The fair value of property is measured utilizing the income approach and utilizing inputs that are primarily based upon internally developed cash flow models discounted at an appropriate weighted average cost of capital. Given the unobservable nature of the inputs, fair value calculations associated with proved oil and gas property impairments are considered Level 3 within the fair value hierarchy. In addition, the signing of a purchase and sale agreement could also trigger an impairment of proved properties. For assets subject to a purchase and sale agreement, the fair value of property is measured pursuant to the terms of the purchase and sale agreement. During the six months ended June 30, 2018, the Company recorded impairments on certain proved oil and gas properties of $397.6 million, resulting in a reduction of the associated carrying amount to fair value. During the six months ended June 30, 2017, the Company recorded no impairments on proved oil and gas properties.

Acquisitions of proved and unproved properties are also measured at fair value on a nonrecurring basis. The Company utilizes a discounted cash flow model to estimate the fair value of acquired property as of the acquisition date which utilizes the following inputs to estimate future net cash flows: (i) estimated quantities of oil and condensate, gas and NGL reserves; (ii) estimates of future commodity prices; and (iii) estimated production rates, future operating and development costs, which are based on the Company's historic experience with similar properties. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage. Due to the unobservable characteristics of the inputs, the fair value of the acquired properties is considered Level 3 within the fair value hierarchy.

Note 7 – Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. In the normal course of business, QEP uses commodity price derivative instruments to reduce the impact of potential downward movements in commodity prices on cash flow, returns on capital investment, and other financial results. However, these instruments typically limit gains from favorable price movements. The volume of production subject to commodity derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. QEP may enter into commodity derivative contracts for up to 100% of forecasted production, but generally, QEP enters into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. In addition, QEP has historically entered into commodity derivative contracts on a portion of its storage transactions. QEP does not enter into commodity derivative contracts for speculative purposes.

QEP uses commodity derivative instruments known as fixed-price swaps or costless collars to realize a known price or price range for a specific volume of production delivered into a regional sales point. QEP's commodity derivative

instruments do not require the physical delivery of oil or gas between the parties at settlement. All transactions are settled in cash with one party paying the other for the net difference in prices, multiplied by the contract volume, for the settlement period. Oil price derivative instruments are typically structured as NYMEX fixed-price swaps based at Cushing, Oklahoma. Gas price derivative instruments are typically structured as fixed-price swaps or collars at NYMEX Henry Hub or regional price indices. QEP also enters into oil and gas basis swaps to achieve a fixed-price swap for a portion of its oil and gas sales at prices that reference specific regional index prices.

QEP does not currently have any commodity derivative transactions that have margin requirements or collateral provisions that would require payments prior to the scheduled settlement dates. QEP's commodity derivative contract counterparties are typically financial institutions and energy trading firms with investment-grade credit ratings. QEP routinely monitors and manages its exposure to counterparty risk by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties' public credit ratings and avoiding the concentration of credit exposure by transacting with multiple counterparties. The Company has master-netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

Derivative Contracts – Production

The following table presents QEP's volumes and average prices for its commodity derivative swap contracts as of June 30, 2018:

Year	Index	Total Volumes (in millions)	Average Swap Price per Unit
Oil sales		(bbls)	($/bbl)
2018	NYMEX WTI	8.3	$ 52.46
2019	NYMEX WTI	9.5	$ 52.66
2020	NYMEX WTI	1.5	$ 60.47
Gas sales		(MMBtu)	($/MMBtu)
2018	NYMEX HH	53.7	$ 3.00
2019	NYMEX HH	43.8	$ 2.86

QEP uses oil and gas basis swaps, combined with NYMEX WTI and NYMEX HH fixed price swaps, to achieve fixed price swaps for the location at which it sells its physical production. The following table presents details of QEP's oil and gas basis swaps as of June 30, 2018:

Year	Index	Basis	Total Volumes (in millions)	Weighted-Average Differential
Oil sales			(bbls)	($/bbl)
2018	NYMEX WTI	Argus WTI Midland	4.6	$ (0.99)
2018	NYMEX WTI	Argus WTI Houston[1]	0.2	$ 6.30
2019	NYMEX WTI	Argus WTI Midland	4.7	$ (0.77)
2019	NYMEX WTI	Argus WTI Houston[1]	0.4	$ 4.35
2020	NYMEX WTI	Argus WTI Midland	1.5	$ (1.01)
Gas sales			(MMBtu)	($/MMBtu)
2018	NYMEX HH	IFNPCR	3.7	$ (0.16)

(1) Argus WTI Houston is an index price reflecting the weighted average price of WTI at Magellan's East Houston crude oil terminal.

QEP Derivative Financial Statement Presentation

The following table identifies the Condensed Consolidated Balance Sheet location of QEP's outstanding derivative contracts on a gross contract basis as opposed to the net contract basis presentation on the Condensed Consolidated Balance Sheets and the related fair values at the balance sheet dates:

	Balance Sheet line item	Gross asset derivative instruments fair value		Gross liability derivative instruments fair value	
		June 30, 2018	December 31, 2017	June 30, 2018	December 31, 2017
Current:		(in millions)			
Commodity	Fair value of derivative contracts	$28.0	$ 20.6	$159.5	$ 120.8
Long-term:					
Commodity	Fair value of derivative contracts	7.3	2.3	51.2	34.0
Total derivative instruments		$35.3	$ 22.9	$210.7	$ 154.8

The effects of the change in fair value and settlement of QEP's derivative contracts recorded in "Realized and unrealized gains (losses) on derivative contracts" on the Condensed Consolidated Statements of Operations are summarized in the following table:

Derivative contracts	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Realized gains (losses) on commodity derivative contracts	(in millions)			
Production				
Oil derivative contracts	$(52.0)	$11.5	$(96.3)	$9.5
Gas derivative contracts	6.4	(5.1)	7.3	(19.3)
Gas Storage				
Gas derivative contracts	0.1	—	0.3	(0.2)
Realized gains (losses) on commodity derivative contracts	(45.5)	6.4	(88.7)	(10.0)
Unrealized gains (losses) on commodity derivative contracts				
Production				
Oil derivative contracts	(20.6)	70.5	(27.5)	174.8
Gas derivative contracts	(13.0)	29.4	(15.8)	100.5
Gas Storage				
Gas derivative contracts	—	0.4	(0.3)	2.3
Unrealized gains (losses) on commodity derivative contracts	(33.6)	100.3	(43.6)	277.6
Total realized and unrealized gains (losses) on commodity derivative contracts	$(79.1)	$106.7	$(132.3)	$267.6

Note 8 – Restructuring

On February 28, 2018, QEP announced its intention to become a pure-play Permian Basin company, which includes plans to market its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley. As a part of the Strategic Initiatives, QEP has incurred or expects to incur costs associated with contractual termination benefits including severance and accelerated vesting of share-based compensation. These termination benefits will be

accounted for under ASC 712, Compensation - Nonretirement Postemployment Benefits and ASC 718, Compensation - Stock Compensation.

Restructuring costs recognized associated with the restructuring are summarized below:

	Three Months Ended June 30, 2018			Six Months Ended June 30, 2018		
	Total recognized	Recognized in "General and administrative"	Recognized in "Net gain (loss) from asset sales, inclusive of restructuring costs"	Total recognized	Recognized in "General and administrative"	Recognized in "Net gain (loss) from asset sales, inclusive of restructuring costs"
	(in millions)					
Termination benefits	$3.6	$ 1.7	$ 1.9	$7.0	$ 5.1	$ 1.9
Office lease termination costs	0.3	0.3	—	0.3	0.3	—
Accelerated share-based compensation	1.2	1.2	—	4.0	4.0	—
Retention expense	6.3	6.3	—	8.0	8.0	—
Pension curtailment	—	—	—	—	—	—
Total restructuring costs	$11.4	$ 9.5	$ 1.9	$19.3	$ 17.4	$ 1.9

	Costs recognized period from inception to June 30, 2018	Total remaining costs expected to be incurred	
	(in millions)		
Termination benefits	$7.0	$ —	(1)
Office lease termination costs	0.3	—	(1)
Accelerated share-based compensation	4.0	—	(1)
Retention expense	8.0	16.0	(2)
Pension curtailment	—	—	(1)
Total restructuring costs	$19.3	$ 16.0	

(1) Due to the nature of the Strategic Initiatives and uncertain factors such as timing and terms of the potential divestitures, the Company is not able to reasonably estimate the total cost to be incurred as a part of this restructuring.

(2) QEP expects to incur an additional $12.0 million of expense in 2018 and $4.0 million in 2019 related to the retention program.

The following table is a reconciliation of QEP's restructuring liability, which is included within "Accounts payable and accrued expenses" on the Condensed Consolidated Balance Sheets.

	Restructuring liability				
	Termination benefits	Office lease termination costs	Accelerated share-based compensation	Retention expense	Total
	(in millions)				
Balance at December 31, 2017	$—	$ —	$ —	$ —	$—

Costs incurred and charged to expense	7.0	0.3	4.0	8.0	19.3
Costs paid or otherwise settled	(3.7)	(0.3)	(4.0)	—	(8.0)
Balance at June 30, 2018[1]	$3.3	$ —	$ —	$ 8.0	$11.3

Note 9 – Debt

As of the indicated dates, the principal amount of QEP's debt consisted of the following:

	June 30, 2018	December 31, 2017
	(in millions)	
Revolving Credit Facility due 2022	$575.0	$ 89.0
6.80% Senior Notes due 2020	51.7	51.7
6.875% Senior Notes due 2021	397.6	397.6
5.375% Senior Notes due 2022	500.0	500.0
5.25% Senior Notes due 2023	650.0	650.0
5.625% Senior Notes due 2026	500.0	500.0
Less: unamortized discount and unamortized debt issuance costs	(24.9)	(27.5)
Total long-term debt outstanding	$2,649.4	$ 2,160.8

Of the total debt outstanding on June 30, 2018, the 6.80% Senior Notes due March 1, 2020, the 6.875% Senior Notes due March 1, 2021, the 5.375% Senior Notes due October 1, 2022 and the 5.25% Senior Notes due May 1, 2023, will mature within the next five years. In addition, the revolving credit facility matures on September 1, 2022.

Credit Facility

QEP's revolving credit facility, which matures, subject to satisfaction of certain conditions, in September 2022, provides for loan commitments of $1.25 billion. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit agreement contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a net funded debt to capitalization ratio that may not exceed 60%, (ii) a leverage ratio under which net funded debt may not exceed 4.00 times consolidated EBITDA (as defined in the credit agreement) commencing with the fiscal quarter ending March 31, 2018, through the fiscal quarter ending December 31, 2018, and 3.75 times thereafter, and (iii) during a ratings trigger period (as defined), a present value coverage ratio under which the present value of the Company's proved reserves must exceed net funded debt by 1.25 times at any time prior to January 1, 2019, must exceed net funded debt by 1.40 times commencing on January 1, 2019 through December 31, 2019, and must exceed net funded debt by 1.50 times at any time on or after January 1, 2020. The Company is currently not subject to the present value coverage ratio. At June 30, 2018 and December 31, 2017, QEP was in compliance with the covenants under the credit agreement.

During the six months ended June 30, 2018, QEP's weighted-average interest rates on borrowings from its credit facility were 4.22%. As of June 30, 2018, QEP had $575.0 million of borrowings outstanding and $0.3 million in letters of credit outstanding under the credit facility. As of December 31, 2017, QEP had $89.0 million of borrowings outstanding and $1.0 million in letters of credit outstanding under the credit facility.

Senior Notes

At June 30, 2018, the Company had $2,099.3 million in principal amount of senior notes outstanding with maturities ranging from March 2020 to March 2026 and coupons ranging from 5.25% to 6.875%. The senior notes pay interest semi-annually, are unsecured senior obligations and rank equally with all of our other existing and future unsecured and senior obligations. QEP may redeem some or all of its senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing QEP's senior notes contain customary events of default and covenants that may limit QEP's ability to, among other things, place liens on its property or assets.

Note 10 – Commitments and Contingencies

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. In each reporting period, the Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its Condensed Consolidated Financial Statements. In accordance with ASC 450, Contingencies, an accrual is recorded for a material loss contingency when its occurrence is probable and damages are reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes.

Legal proceedings are inherently unpredictable and unfavorable resolutions can occur. Assessing contingencies is highly subjective and requires judgment about uncertain future events. When evaluating contingencies related to legal proceedings, the Company may be unable to estimate losses due to a number of factors, including potential defenses, the procedural status of the matter in question, the presence of complex legal and/or factual issues, the ongoing discovery and/or development of information important to the matter.

Landowner Litigation – In October, 2017, the owners of certain surface and mineral interests in Martin and Andrews County, Texas filed suit against QEP, alleging QEP improperly used the surface of the properties and failed to correctly pay royalties, and are seeking money damages and a declaratory judgment that portions of the oil and gas leases covering the properties are no longer in effect. The Company continues to evaluate the allegations and its defenses. The Company is unable to make an estimate of the reasonably possible loss at this early stage.

Note 11 – Share-Based Compensation

In 2018, QEP's Board of Directors and QEP's shareholders approved the QEP Resources, Inc. 2018 Long-Term Incentive Plan (LTIP), which replaces the 2010 Long-Term Stock Incentive Plan (LTSIP) and provides for the issuance of up to 10.0 million shares such that the Board of Directors may grant long-term incentive compensation. QEP issues stock options, restricted share awards, and restricted share units under its LTIP and awards performance share units under its Cash Incentive Plan (CIP) to certain officers, employees and non-employee directors. Grants issued prior to May 15, 2018 are under the LTSIP and the grants issued on or after May 15, 2018 are under the LTIP. QEP recognizes the expense over the vesting periods for the stock options, restricted share awards, restricted share units and performance share units. There were 10.0 million shares available for future grants under the LTIP at June 30, 2018.

Share-based compensation expense is recognized within "General and administrative" expense on the Condensed Consolidated Statements of Operations and is summarized in the table below. During the three and six months ended June 30, 2018, the Company recorded an additional $1.2 million and $4.0 million, respectively, of share-based compensation expense related to the acceleration of vesting that occurred as part of the restructuring program and included in share-based compensation expense below (refer to Note 8 – Restructuring for additional information):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Stock options	$0.2	$0.6	$0.7	$1.2
Restricted share awards	6.8	6.0	15.6	13.3
Performance share units	5.1	(4.9)	7.0	(6.8)
Restricted share units	0.1	—	0.1	—
Total share-based compensation expense	$12.2	$1.7	$23.4	$7.7

Stock Options

QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock option awards at the date of grant. Fair value calculations rely upon subjective assumptions used in the mathematical model and may not be representative of future results. The Black-Scholes-Merton model is intended for calculating the value of stock options not traded on an exchange. The Company utilizes the "simplified" method to estimate the expected term of the stock options granted as there is limited historical exercise data available in estimating the expected term of the stock options. QEP uses a historical volatility method to estimate the fair value of stock options awards and the risk-free

interest rate is based on the yield on U.S. Treasury strips with maturities similar to those of the expected term of the stock options. The stock options typically vest in equal installments over a three-year period from the grant date and are exercisable immediately upon vesting through the seventh anniversary of the grant date. To fulfill options exercised, QEP either reissues treasury stock or issues new shares. The Company recognizes forfeitures of stock options as they occur.

In 2018, QEP did not issue stock options to better align our long-term incentive awards with those typical of the industry.

Stock option transactions under the terms of the LTSIP are summarized below:

	Options Outstanding	Weighted-Average Exercise Price (per share)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2017	2,354,277	$ 23.62		
Exercised	(23,337)	10.12		
Canceled	(202,235)	39.07		
Outstanding at June 30, 2018	2,128,705	$ 22.30	3.32	$ 1.0
Options Exercisable at June 30, 2018	1,734,134	$ 24.07	2.87	$ 0.6
Unvested Options at June 30, 2018	394,571	$ 14.51	5.31	$ 0.3

The total intrinsic value (the difference between the market price at the exercise date and the exercise price) of stock options exercised was $0.1 million during the six months ended June 30, 2018. During the six months ended June 30, 2017, there were no exercises of stock options. As of June 30, 2018, $0.9 million of unrecognized compensation expense related to stock options granted under the LTSIP is expected to be recognized over a weighted-average vesting period of 1.63 years. The weighted-average vesting period may be reduced due to accelerated vestings under the restructuring program (refer to Note 8 – Restructuring for additional information).

Restricted Share Awards

Restricted share award grants typically vest in equal installments over a three-year period from the grant date. The grant date fair value is determined based on the closing bid price of the Company's common stock on the grant date. The Company recognizes restricted share forfeitures as they occur. The total fair value of restricted share awards that vested during the six months ended June 30, 2018 and 2017 was $24.6 million and $20.3 million, respectively. The weighted-average grant date fair value of restricted share awards was $9.55 per share and $16.69 per share for the six months ended June 30, 2018 and 2017, respectively. As of June 30, 2018, $30.2 million of unrecognized compensation expense related to restricted share awards granted under the LTSIP and LTIP is expected to be recognized over a weighted-average vesting period of 2.37 years. The weighted-average vesting period may be reduced due to accelerated vestings under the restructuring program (refer to Note 8 – Restructuring for additional information).

Transactions involving restricted share awards under the terms of the LTSIP and LTIP are summarized below:

	Restricted Share Awards Outstanding	Weighted-Average Grant Date Fair Value (per share)
Unvested balance at December 31, 2017	3,721,334	$ 13.23
Granted	2,933,607	9.55
Vested	(1,743,969)	14.12
Forfeited	(127,920)	11.19
Unvested balance at June 30, 2018	4,783,052	$ 10.71

Performance Share Units

The payouts for performance share units are dependent upon the Company's total shareholder return compared to a group of its peers over a three-year period. The awards are denominated in share units and have historically been paid in cash. Beginning with awards granted in 2015, the Company has the option to settle earned awards in cash or shares of common stock under the Company's LTIP; however, as of June 30, 2018, the Company expects to settle all awards in cash under the CIP. These awards are classified as liabilities and are included within "Other long-term liabilities" on the Condensed Consolidated Balance Sheets. As these awards are dependent upon the Company's total shareholder return and stock price, they are remeasured at fair value at the end of each reporting period. The weighted-average grant date fair value of the performance share units was $9.55 per share and $16.98 per share for the six months ended June 30, 2018 and 2017, respectively. As of June 30, 2018, $16.4 million of unrecognized compensation expense, which represents the unvested portion of the fair market value of performance shares granted, is expected to be recognized over a weighted-average vesting period of 2.19 years. The weighted-average vesting period may be reduced due to accelerated vestings under the restructuring program (refer to Note 8 – Restructuring for additional information).

Transactions involving performance share units under the terms of the CIP are summarized below:

	Performance Share Units Outstanding	Weighted-Average Grant Date Fair Value (per share)
Unvested balance at December 31, 2017	1,199,336	$ 14.59
Granted	724,095	9.55
Vested	(277,604)	19.73
Unvested balance at June 30, 2018	1,645,827	$ 11.47

Restricted Share Units

Employees may elect to defer their grants of restricted share awards and these deferred awards are designated as restricted share units. Restricted share units vest over a three-year period and are deferred into the Company's nonqualified, unfunded deferred compensation plan at the time of vesting. These awards are ultimately paid in cash. They are classified as liabilities and are included in "Other long-term liabilities" on the Condensed Consolidated Balance Sheets and are measured at fair value at the end of each reporting period. The weighted-average grant date fair value of the restricted share units was $9.55 and $16.98 per share for the six months ended June 30, 2018 and 2017, respectively. As of June 30, 2018, $0.4 million of unrecognized compensation expense, which represents the unvested portion of the fair market value of restricted share units granted, is expected to be recognized over a weighted-average vesting period of 1.70 years. The weighted-average vesting period may be reduced due to accelerated vestings under the restructuring program (refer to Note 8 – Restructuring for additional information).

Transactions involving restricted share units under the terms of the LTSIP are summarized below:

	Restricted Share Units Outstanding	Weighted-Average Grant Date Fair Value (per share)
Unvested balance at December 31, 2017	21,946	$ 13.22
Granted	31,835	9.55
Vested	(9,320)	12.56
Unvested balance at June 30, 2018	44,461	$ 10.73

Note 12 – Employee Benefits

Pension and Other Postretirement Benefits

The Company provides pension and other postretirement benefits to certain employees through three retiree benefit plans: the QEP Resources, Inc. Retirement Plan (the Pension Plan), the Supplemental Executive Retirement Plan (the SERP), and a postretirement medical plan (the Medical Plan).

The Pension Plan is a closed, qualified, defined-benefit pension plan that is funded and provides pension benefits to certain QEP employees. During the six months ended June 30, 2018, the Company made contributions of $3.0 million to the Pension Plan and expects to make an additional $1.0 million to the Pension Plan during the remainder of 2018. Contributions to the Pension Plan increase plan assets. The Pension Plan was amended in June 2015 and was frozen effective January 1, 2016, such that employees do not earn additional defined benefits for future services. During the six months ended June 30, 2018, the Company has not made discretionary contributions to active participants of the Pension Plan but expects to contribute $0.4 million to eligible participants in the fourth quarter of 2018.

The SERP is a nonqualified retirement plan that is unfunded and provides pension benefits to certain QEP employees. During the six months ended June 30, 2018, the Company made contributions of $0.5 million to its SERP and expects to contribute an additional $0.2 million to its SERP during the remainder of 2018. Contributions to the SERP are used to fund current benefit payments. The SERP was amended and restated in June 2015 and was closed to new participants effective January 1, 2016.

The Medical Plan is a self-insured plan. It is unfunded and provides other postretirement benefits including certain health care and life insurance benefits for certain retired QEP employees. During the six months ended June 30, 2018, the Company made contributions of $0.1 million to its Medical Plan and expects to contribute an additional $0.1 million to its Medical Plan during the remainder of 2018. Contributions to the Medical Plan are used to fund current benefit payments.

In February 2017, the Company changed the eligibility requirements for active employees eligible for the Medical Plan, as well as retirees currently enrolled. Effective July 1, 2017, the Company no longer offers the Medical Plan to retirees and spouses that are both Medicare eligible. In addition, the Company no longer offers life insurance to individuals retiring on or after July 1, 2017.

The Company's Strategic Initiatives may trigger curtailments related to the Pension Plan, SERP and/or Medical Plan at the closing of the various transactions (refer to Note 8 – Restructuring for more information).

The Company recognizes service costs related to SERP and Medical Plan benefits on the Condensed Consolidated Statements of Operations within "General and administrative" expense. All other expenses related to the Pension Plan, SERP and Medical Plan are recognized on the Condensed Consolidated Statements of Operations within "Interest and other income (expense)".

The following table sets forth the Company's net periodic benefit costs related to its Pension Plan, SERP and Medical Plan:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Pension Plan and SERP benefits	(in millions)			
Service cost	$0.2	$0.1	$0.4	$0.4
Interest cost	1.1	1.2	2.2	2.4
Expected return on plan assets	(1.5)	(1.4)	(2.9)	(2.7)
Amortization of prior service costs[1]	0.2	0.3	0.4	0.6
Amortization of actuarial losses[1]	0.3	(0.1)	0.6	0.2
Periodic expense	$0.3	$0.1	$0.7	$0.9
Medical Plan benefits				
Interest cost	$0.1	$0.1	$0.1	$0.1
Amortization of prior service costs[1]	—	—	(0.1)	(0.1)
Periodic expense	$0.1	$0.1	$—	$—

(1) Amortization of prior service costs and actuarial losses out of accumulated other comprehensive income are recognized on the Condensed Consolidated Statements of Operations within "Interest and other income (expense)".

Employee Investment Plan

QEP employees may participate in the QEP Employee Investment Plan, a defined-contribution plan (the 401(k) Plan). The 401(k) Plan allows eligible employees to make investments, including purchasing shares of QEP common stock, through payroll deduction at the current fair market value on the transaction date. Both employees and QEP make contributions to the 401(k) Plan. During the six months ended June 30, 2018, the Company made contributions of $3.6 million to the 401(k) Plan and expects to contribute an additional $2.4 million to the 401(k) Plan during the remainder of 2018. Due to the Company's Strategic Initiatives, the amount expected to be contributed to the 401(k) Plan is subject to change (refer to Note 8 – Restructuring for more information).

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

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company's operating results. MD&A should be read in conjunction with the Condensed Consolidated Financial Statements and related Notes included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

The following information updates the discussion of QEP's financial condition provided in its Annual Report on Form 10-K for the year ended December 31, 2017 (2017 Form 10-K) and analyzes the changes in the results of operations between the three and six months ended June 30, 2018 and 2017. For definitions of commonly used oil and gas terms found in this Quarterly Report on Form 10-Q, please refer to the "Glossary of Terms" provided in the 2017 Form 10-K.

OVERVIEW

QEP Resources, Inc. is an independent crude oil and natural gas exploration and production company with operations in two regions of the United States: the Southern Region (primarily in Texas and Louisiana) and the Northern Region (primarily in North Dakota and Utah). Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its subsidiaries on a consolidated basis. QEP's corporate headquarters are located in Denver, Colorado and shares of QEP's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "QEP".

In February 2018, QEP's Board of Directors unanimously approved certain strategic and financial initiatives (Strategic Initiatives), including plans to market its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley and focus its activities in the Permian Basin. As a part of this process, the Company engaged advisors to assist with the divestitures of its Williston Basin and Uinta Basin assets and provided data for potential buyers to evaluate. We continue to engage in discussions with several potential buyers regarding the sale of all or a portion of our Williston assets. As a part of the Strategic Initiatives, QEP has incurred or expects to incur costs associated with contractual termination benefits including severance and accelerated vesting of share-based compensation. Refer to Note 3 – Acquisitions and Divestitures and Note 8 – Restructuring, in Item I of Part I of this Quarterly Report on Form 10-Q for additional information.

On July 5, 2018, the Company's wholly owned subsidiary, QEP Energy Company, entered into a definitive agreement to sell natural gas and oil producing properties, undeveloped acreage and related assets located in the Uinta Basin for proceeds of $155.0 million, subject to customary purchase price adjustments (the Uinta Basin Divestiture). The transaction is expected to close in September 2018. Since the transaction was substantially finalized at June 30, 2018, the assets and liabilities associated with the Uinta Basin Divestiture have been classified as noncurrent assets and liabilities held for sale on the Condensed Consolidated Balance Sheets and the notes accompanying the Condensed Consolidated Financial Statements. Pursuant to signing a purchase and sale agreement for the Uinta Basin Divestiture, QEP recorded $402.8 million of proved and unproved properties impairment during the six months ended June 30, 2018. In addition, QEP recorded $1.9 million of estimated restructuring costs related to this divestiture during the six months ended June 30, 2018 included in the "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Condensed Consolidated Statements of Operations. Refer to Note 1 – Basis of Presentation, Note 3 – Acquisitions and Divestitures and Note 8 – Restructuring, in Item I of Part I of this Quarterly Report on Form 10-Q for more information.

Since the beginning of 2014, the Company has made approximately $2.5 billion of acquisitions of properties in the Permian Basin and spent approximately 40% of its capital expenditures (excluding property acquisitions) on its properties in the Permian Basin. In 2018, the Company plans to spend approximately 70% of total planned capital expenditures to develop the Permian Basin.

Outlook

The Company continues to focus on reducing its operating costs and per well drilling costs and managing its liquidity as it executes on its plan to transition from a natural gas weighted company to a pure play Permian Basin company. We believe our balance sheet and sufficient liquidity will allow us to grow oil and condensate production in the Permian Basin and achieve our Strategic Initiatives.

Based on current commodity prices, we expect to be able to fund our planned capital program for the remainder of 2018 with cash flow from operating activities and borrowings under our credit facility. Our total capital expenditures (excluding property acquisitions) for 2018 are expected to be approximately $1,120.0 million, a decrease of approximately 8% from 2017 capital expenditures. We continuously evaluate our level of drilling and completion activity in light of drilling results, commodity prices and changes in our operating and development costs and may adjust our capital investment program based on such evaluations. See "Cash Flow from Investing Activities" for further discussion of our capital expenditures.

Acquisitions and Divestitures

While we believe our extensive inventory of identified drilling locations provides a solid base for growth in production and reserves, the Company continues to evaluate and acquire properties in the Permian Basin to add

additional development opportunities and facilitate the drilling of long lateral wells.

Acquisitions

During the six months ended June 30, 2018, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage in the Permian Basin for an aggregate purchase price of $45.1 million, subject to customary purchase price adjustments. Of the $45.1 million, $37.5 million was related to acquisitions from various persons who owned additional oil and gas interests in certain properties included in the 2017 Permian Basin Acquisition on substantially the same terms and conditions as the 2017 Permian Basin Acquisition.

In the fourth quarter of 2017, QEP acquired additional oil and gas properties in the Permian Basin (the 2017 Permian Basin Acquisition) for an aggregate purchase price of $720.7 million, subject to post-closing purchase price adjustments. The 2017 Permian Basin Acquisition consists of approximately 15,100 acres, mainly in Martin County, Texas, which are held by production from existing vertical wells. QEP structured the transaction as a like-kind exchange under Section 1031 of the Internal Revenue Service Code and funded the purchase price with the proceeds from the sale of QEP's Pinedale assets.

During the six months ended June 30, 2017, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage and additional surface acreage in the Permian Basin, for an aggregate purchase price of $76.6 million. In conjunction with these acquisitions, the Company recorded $5.3 million of goodwill, which was subsequently impaired in 2017.

Divestitures

During the six months ended June 30, 2018, QEP recorded a pre-tax loss of $1.9 million related to estimated restructuring costs associated with the Uinta Basin Divestiture (refer to Note 8 – Restructuring, in Item I of Part I of this Quarterly Report on Form 10-Q for more information), partially offset by a pre-tax gain of $0.7 million related to the divestiture of properties outside our main operating areas in the Uinta Basin, Pinedale and Other Northern area, and the sale of an underground gas storage facility, in which QEP received aggregate net cash proceeds of $48.8 million. In addition, QEP recorded a pre-tax gain of $0.8 million related to the sale of QEP's assets in Pinedale (the Pinedale Divestiture).

In September 2017, QEP closed on the Pinedale Divestiture for net cash proceeds (after purchase price adjustments) of $718.2 million. For the six months ended June 30, 2018, QEP recorded a pre-tax gain on sale of $0.8 million, due to post-closing purchase price adjustments, which was recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Condensed Consolidated Statements of Operations. During the year ended December 31, 2017, QEP recorded a pre-tax gain on sale of $180.4 million, which was recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations. In connection with the Pinedale Divestiture, QEP agreed to reimburse the buyer for certain deficiency charges it incurs related to gas processing and NGL transportation and fractionation contracts between the effective date of the sale and December 31, 2019, in an aggregate amount not to exceed $45.0 million. As of June 30, 2018, the remaining liability associated with estimated future payments for this commitment was $23.8 million.

Financial and Operating Highlights

During the three months ended June 30, 2018, QEP:

- Delivered record oil and condensate production of 6.6 MMbbls, a 35% increase over 2017 volumes;
- Increased oil and condensate production by 121% to a record 3.2 MMbbls in the Permian Basin;
- Increased gas production in Haynesville/Cotton Valley to 28.5 Bcf, a 71% increase over 2017 volumes, primarily due to successful refracturing and drilling programs;
- Reported net realized oil prices of $54.30 per bbl, a 16% increase over 2017;
- Repurchased and retired 0.6 million shares of the Company's outstanding shares of common stock for $5.6 million;
- Generated a net loss of $336.0 million or $1.42 per diluted share; and
- Reported Adjusted EBITDA (a non-GAAP financial measure defined and reconciled below) of $282.6 million, a 59% increase over 2017.

During the six months ended June 30, 2018, QEP:

- Delivered oil and condensate production of 11.5 MMbbls, a 21% increase over 2017 volumes;
- Increased oil and condensate production by 119% to a record 5.4 MMbbls in the Permian Basin;
- Increased gas production in Haynesville/Cotton Valley to 54.2 Bcf, an 88% increase over 2017 volumes, primarily due to successful refracturing and drilling programs;
- Reported net realized oil prices of $53.11 per bbl, a 13% increase over 2017;
- Repurchased and retired 6.2 million shares of the Company's outstanding shares of common stock for $58.4 million;
- Generated a net loss of $389.6 million, or $1.63 per diluted share; and
- Reported Adjusted EBITDA (a non-GAAP financial measure defined and reconciled below) of $454.5 million, a 31% increase over 2017.

Factors Affecting Results of Operations

Supply, Demand, Market Risk and their Impact on Oil and Gas Prices
Oil and gas prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, strength of the U.S. dollar and other factors. In recent years, oil and gas prices have been affected by supply growth, particularly in U.S. oil and gas production, driven by advances in drilling and completion technologies, and fluctuations in demand driven by a variety of factors.

Changes in the market prices for oil, gas and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling and completion activity and related capital expenditures, our proved undeveloped (PUD) reserves conversion rate, liquidity, rate of growth, costs of goods and services required to drill, complete and operate wells, and the carrying value of its oil and gas properties. Historically, field-level prices received for QEP's oil and gas production have been volatile. During the past five years, the posted price for WTI crude oil has ranged from a low of $26.19 per barrel in February 2016 to a high of $110.62 per barrel in September 2013. The Henry Hub spot market price of natural gas has ranged from a low of $1.49 per MMBtu in March 2016 to a high of $8.15 per MMBtu in February 2014. If prices of oil, gas or NGL decline to early 2016 levels or further, our operations, financial condition and level of expenditures for the development of our oil and gas reserves may be materially and adversely affected.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the global economy, including Europe and China's economic outlook; the Organization of Petroleum Exporting Countries (OPEC) countries oil production and policies regarding production quotas; political unrest and economic issues in South America, Asia, Europe, the Middle East, and Africa; slowing growth in certain emerging market economies; actions taken by the United States Congress and the president of the United States; the U.S. federal budget deficit; changes in regulatory oversight policy; commodity price volatility; tariffs on goods we use in our operations or on the products we sell; the impact of a potential increase in interest rates; volatility in various global currencies; and other factors. A dramatic decline in regional or global economic conditions, a major recession or depression, regional political instability, economic sanctions, war, or other factors beyond the control of QEP could have a significant impact on oil, gas and NGL supply, demand and prices and the Company's ability to continue its planned drilling programs and could materially impact the Company's financial position, results of operations and cash flow from operations. Disruption to the global oil supply system, political and/or economic instability, fluctuations in currency values, and/or other factors could trigger additional volatility in oil prices.

Due to continued global economic uncertainty and the corresponding volatility of commodity prices, QEP continues to focus on maintaining a sufficient liquidity position to ensure financial flexibility. QEP uses commodity derivatives to reduce the volatility of the prices QEP receives for a portion of its production and to partially protect cash flow and returns on invested capital from a drop in commodity prices. Generally, QEP intends to enter into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. At June 30, 2018, QEP forecasted its 2018 annual production to be approximately 51.1 MMboe and had approximately 66% of its forecasted oil production and 69% of its forecasted gas production covered with fixed-price swaps and collars. See Part 1, Item 3 – "Quantitative and Qualitative Disclosures about Market Risk-Commodity Price Risk Management" for further details on QEP's commodity derivatives transactions.

Potential for Future Asset Impairments
The carrying values of the Company's properties are sensitive to declines in oil, gas and NGL prices as well as increases in various development and operating costs and expenses and, therefore, are at risk of impairment. The Company uses a cash flow model to assess its proved properties for impairment. The cash flow model includes numerous assumptions, including estimates of future oil, gas and NGL production, estimates of future prices for

production that are based on the price forecast that management uses to make investment decisions, including estimates of basis differentials, future operating costs, transportation expenses, production taxes, and development costs that management believes are consistent with its price forecast, and discount rates. Management also considers a number of other factors, including the forward curve for future oil and gas prices, and developments in regional transportation infrastructure when developing its estimate of future prices for production. All inputs for the cash flow model are evaluated at each date of estimate.

We base our fair value estimates on projected financial information that we believe to be reasonably likely to occur. An assessment of the sensitivity of our capitalized costs to changes in the assumptions in our cash flow calculations is not practicable, given the numerous assumptions (e.g., future oil, gas and NGL prices; production and reserves; pace and timing of development plans; timing of capital expenditures; operating costs; drilling and development costs; and inflation and discount rates) that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced oil, gas and NGL prices on future undiscounted cash flows would likely be offset by lower drilling and development costs and lower operating costs.

If forward oil and gas prices decline significantly from June 30, 2018 levels or we experience negative changes in estimated reserve quantities or we enter into purchase and sale agreements for less than net book value, we have proved and unproved property with a net book value of approximately $2.7 billion at risk for impairment, associated with the Williston Basin and proved and unproved property and gathering assets with a net book value of approximately $718 million at risk for impairment, associated with Haynesville/Cotton Valley as of June 30, 2018. The actual amount of impairment incurred, if any, for these properties will depend on a variety of factors including, but not limited to, subsequent forward price curve changes, entering into purchase and sale agreements for less than net book value of the assets, the additional risk-adjusted value of probable and possible reserves associated with the properties, weighted-average cost of capital, operating cost estimates and future capital expenditure estimates.

Multi-Well Pad Drilling and Completion

To reduce the costs of well location construction and rig mobilization and demobilization and to obtain other efficiencies, QEP utilizes multi-well pad drilling where practical. For example, in the Permian Basin QEP utilizes "tank-style" development, in which we simultaneously develop multiple subsurface targets by drilling and completing all wells in a given "tank" before any individual well is turned to production. In certain of our producing areas, wells drilled on a pad are not completed and brought into production until all wells on the pad are drilled and the drilling rig is moved from the location. As a result, multi-well pad drilling delays the completion of wells and the commencement of production. In addition, existing wells that offset new wells being completed by QEP or offset operators may need to be temporarily shut-in during the completion process. Such delays and well shut-ins have caused and may continue to cause volatility in QEP's quarterly operating results. In addition, delays in completion of wells may impact planned conversion of PUD reserves to proved developed reserves.

Uncertainties Related to Claims

QEP is currently subject to claims that could adversely impact QEP's liquidity, operating results and/or capital expenditures for a particular reporting period, including, but not limited to those described in Note 10 – Commitments and Contingencies, in Item 1 of Part I of this Quarterly Report on Form 10-Q. Given the uncertainties involved in these matters, QEP is unable to predict the ultimate outcomes.

Critical Accounting Estimates

QEP's significant accounting policies are described in Item 7 of Part II of its 2017 Form 10-K. The Company's Condensed Consolidated Financial Statements are prepared in accordance with GAAP. The preparation of the Company's Condensed Consolidated Financial Statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. QEP's accounting policies on oil and gas reserves, successful efforts accounting for oil and gas operations, capitalized exploratory well costs, impairment of long-lived assets, asset retirement obligations, revenue recognition, litigation and other contingencies, environmental obligations, derivative contracts, pension and other postretirement benefits, share-based compensation, income taxes and purchase price allocations, among others, may involve a high degree of complexity and judgment on the part of management.

Drilling, Completion and Production Activities

The following table presents operated and non-operated wells in the process of being drilled or waiting on completion at June 30, 2018:

		Operated				Non-operated			
	Drilling	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Rigs	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region									
Williston Basin	—	—	—	—	—	1	—	9	0.1
Uinta Basin	—	—	—	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—	—
Southern Region									
Permian Basin[1]	5	25	24.8	27	26.5	—	—	—	—
Haynesville/Cotton Valley	—	—	—	1	1.0	3	0.2	7	0.3
Other Southern	—	—	—	—	—	—	—	—	—

(1) The gross operated drilling well count in the Permian Basin includes 13 wells for which surface casing has been set, but as of June 30, 2018, did not have a rig drilling.

Each gross well completed in more than one producing zone is counted as a single well. Delays and well shut-ins resulting from multi-well pad drilling have caused and may continue to cause volatility in QEP's quarterly operating results. In addition, delays in completion of wells could impact planned conversion of PUD reserves to proved developed reserves. QEP had 28 gross operated wells waiting on completion as of June 30, 2018.

The following table presents the number of operated and non-operated wells completed and turned to sales (put on production) for the three and six months ended June 30, 2018:

	Operated Put on Production				Non-operated Put on Production			
	Three Months Ended June 30, 2018		Six Months Ended June 30, 2018		Three Months Ended June 30, 2018		Six Months Ended June 30, 2018	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Williston Basin	11	10.1	11	10.1	2	0.1	2	0.1
Uinta Basin	—	—	2	2.0	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Permian Basin	37	36.1	68	67.1	—	—	—	—
Haynesville/Cotton Valley	1	1.0	3	3.0	3	0.1	9	0.5
Other Southern	—	—	—	—	—	—	—	—

The following table presents the number of operated wells in the process of being drilled or waiting on completion at June 30, 2018 and operated wells completed and turned to sales (put on production) for the six months ended June 30, 2018:

	Permian Basin		Williston Basin		Haynesville/Cotton Valley		Uinta Basin	
	As of June 30, 2018							
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Well Progress								
Drilling	25	24.8	—	—	—	—	—	—
At total depth - under drilling rig	2	2.0	—	—	—	—	—	—
Waiting to be completed	12	11.7	—	—	—	—	—	—
Undergoing completion	5	4.8	—	—	—	—	—	—
Completed, awaiting production	8	8.0	—	—	1	1.0	—	—
Waiting on completion	27	26.5	—	—	1	1.0	—	—
Put on production	68	67.1	11	10.1	3	3.0	2	2.0

RESULTS OF OPERATIONS

Net Income

QEP generated a net loss during the second quarter of 2018 of $336.0 million, or $1.42 per diluted share, compared to net income of $45.4 million, or $0.19 per diluted share, in the second quarter of 2017. QEP's net loss was primarily due to a $403.7 million increase in impairment expense and a $185.8 million increase in unrealized and realized derivative losses. These increases to the net loss were partially offset by a $192.5 million increase in oil and condensate sales due to a 35% increase in oil and condensate production and a 16% increase in average net realized oil prices in the second quarter of 2018 compared to the second quarter of 2017.

QEP generated a net loss during the first half of 2018 of $389.6 million or $1.63 per diluted share, compared to net income of $122.3 million or $0.51 per diluted share, in the first half of 2017. QEP's net loss was primarily due to a $404.3 million increase in impairment expense and a $399.9 million increase in unrealized and realized derivative losses. These increases to the net loss were partially offset by a $271.5 million increase in oil and condensate sales due to a 21% increase in oil and condensate production and a 13% increase in average net realized oil prices in the first half of 2018 compared to the first half of 2017.

Adjusted EBITDA (Non-GAAP)

Management defines Adjusted EBITDA (a non-GAAP measure) as earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA), adjusted to exclude changes in fair value of derivative contracts, exploration expenses, gains and losses from asset sales, impairment and certain other items. Management uses Adjusted EBITDA to evaluate QEP's financial performance and trends, make operating decisions and allocate resources. Management believes the measure is useful supplemental information for investors because it eliminates the impact of certain nonrecurring, non-cash and/or other items that management does not consider as indicative of QEP's performance from period to period. QEP's Adjusted EBITDA may be determined or calculated differently than similarly titled measures of other companies in our industry, which would reduce the usefulness of this non-GAAP financial measure when comparing our performance to that of other companies.

Below is a reconciliation of net income (loss) (a GAAP measure) to Adjusted EBITDA. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Net income (loss)	$(336.0)	$45.4	$(389.6)	$122.3
Interest expense	38.2	34.9	73.2	68.7
Interest and other (income) expense	3.1	(1.8)	3.8	(2.4)
Income tax provision (benefit)	(106.2)	27.3	(120.1)	72.9
Depreciation, depletion and amortization	242.2	191.5	438.7	383.3
Unrealized (gains) losses on derivative contracts	33.6	(100.3)	43.6	(277.6)
Exploration expenses	0.1	—	0.1	0.4
Net (gain) loss from asset sales, inclusive of restructuring costs	3.9	(19.8)	0.4	(19.8)
Impairment	403.7	—	404.4	0.1
Adjusted EBITDA	$282.6	$177.2	$454.5	$347.9

Adjusted EBITDA increased to $282.6 million in the second quarter of 2018 from $177.2 million in the second quarter of 2017, primarily due to a 35% increase in oil and condensate production, mainly in the Permian Basin, a 16% increase in average net realized oil prices and a 71% increase in gas production in Haynesville/Cotton Valley. These changes were partially offset by a $51.9 million increase in realized derivative losses, a $36.4 million decrease in gas sales primarily due to the Pinedale divestiture, and a 4% reduction in average net realized gas prices in the second quarter of 2018 compared to the second quarter of 2017.

Adjusted EBITDA increased to $454.5 million in the first half of 2018 from $347.9 million in the first half of 2017, primarily from a 21% increase in oil and condensate production, mainly in the Permian Basin, a 13% increase in average net realized oil prices and an 88% increase in gas production in Haynesville/Cotton Valley. These increases in the first half of 2018 compared to the first half of 2017 were partially offset by a $78.7 million increase in realized derivative losses and a $68.9 million decrease in gas sales, primarily due to the Pinedale Divestiture.

Revenue

The following table presents our revenues disaggregated by revenue source.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017[1]	Change	2018	2017[1]	Change
				(in millions)		
Oil and condensate sales	$408.5	$216.0	$192.5	$709.2	$437.7	$271.5
Gas sales	97.8	134.2	(36.4)	199.8	268.7	(68.9)
NGL sales	26.4	22.8	3.6	46.2	51.8	(5.6)
Oil and condensate, gas and NGL sales, as adjusted[2]	532.7	373.0	$159.7	955.2	758.2	197.0
Transportation and processing costs included in revenue[3]	(12.4)	—	(12.4)	(25.1)	—	(25.1)
Oil and condensate, gas and NGL sales, as presented	$520.3	$373.0	$147.3	$930.1	$758.2	$171.9

(1) Prior period amounts have not been adjusted under the modified retrospective method for the new revenue recognition rule, refer to Note 2 – Revenue in Part 1, Item I of this Quarterly Report on Form 10-Q.

(2) Above is a reconciliation of Oil and condensate, gas and NGL sales (a GAAP measure) as presented on the Condensed Consolidated Statements of Operations to Oil and condensate, gas and NGL sales, as adjusted. Oil and condensate, gas and NGL sales, as adjusted excludes transportation and processing costs that are included as part of "Oil and condensate, gas and NGL sales" on the Condensed Consolidated Statements of Operations. Management removes these costs from "Oil and condensate, gas and NGL sales" included on the Condensed Consolidated Statements of Operations to reflect total revenue associated with its production prior to deducting any expenses. Management believes that this non-GAAP measure is useful supplemental information for investors as it is reflective of the total revenue generated from its wells for the period and is a more comparable measure to reported revenue of its peers. This non-GAAP measure should be considered by the reader in addition to but not instead of, the financial statements prepared in accordance with GAAP. Refer to Note 2 – Revenue in Part 1, Item I of this Quarterly Report on Form 10-Q.

(3) Transportation and processing costs in the table above is not representative of total transportation and processing costs incurred. Refer to the Operating Expenses section below for a reconciliation of total transportation and processing costs.

Revenue, Volume and Price Variance Analysis

The following table shows volume and price related changes for each of QEP's adjusted production-related revenue categories for the three and six months ended June 30, 2018, compared to the three and six months ended June 30, 2017:

	Oil and condensate	Gas	NGL	Total
	(in millions)			
Oil and condensate, gas and NGL sales, as adjusted				
Three months ended June 30, 2017	$216.0	$134.2	$22.8	$373.0
Changes associated with volumes[1]	75.3	(21.9)	(3.4)	50.0
Changes associated with prices[2]	117.2	(14.5)	7.0	109.7
Three months ended June 30, 2018	$408.5	$97.8	$26.4	$532.7
Oil and condensate, gas and NGL sales, as adjusted				
Six months ended June 30, 2017	$437.7	$268.7	$51.8	$758.2
Changes associated with volumes[1]	91.1	(44.8)	(12.5)	33.8
Changes associated with prices[2]	180.4	(24.1)	6.9	163.2
Six months ended June 30, 2018	$709.2	$199.8	$46.2	$955.2

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volume from the three and six months ended June 30, 2018, as compared to the three and six months ended June 30, 2017, by the average field-level price for the three and six months ended June 30, 2017.

(2) The revenue variance attributed to the change in price is calculated by multiplying the change in average field-level price from the three and six months ended June 30, 2018, as compared to the three and six months ended June 30, 2017, by the respective volumes for the three and six months ended June 30, 2018. Pricing changes are driven by changes in commodity average field-level prices, excluding the impact from commodity derivatives.

Production and Pricing

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Total production volumes (Mboe)						
Northern Region						
Williston Basin	4,459.7	4,573.9	(114.2)	8,189.4	9,407.9	(1,218.5)
Pinedale	—	3,316.7	(3,316.7)	0.1	6,831.6	(6,831.5)
Uinta Basin	821.7	897.0	(75.3)	1,626.2	1,865.3	(239.1)
Other Northern	42.8	337.1	(294.3)	148.2	667.5	(519.3)
Southern Region						
Permian Basin	4,016.2	1,932.1	2,084.1	6,799.1	3,321.6	3,477.5
Haynesville/Cotton Valley	4,761.3	2,792.3	1,969.0	9,051.8	4,839.0	4,212.8
Other Southern	4.4	11.5	(7.1)	15.9	18.0	(2.1)
Total production	14,106.1	13,860.6	245.5	25,830.7	26,950.9	(1,120.2)
Total equivalent prices (per Boe)						
Average field-level equivalent price	$37.77	$26.91	$10.86	$36.98	$28.13	$8.85
Commodity derivative impact	(3.23)	0.46	(3.69)	(3.45)	(0.36)	(3.09)
Net realized equivalent price	$34.54	$27.37	$7.17	$33.53	$27.77	$5.76

Oil and Condensate Volumes and Prices

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Oil and condensate production volumes (Mbbl)						
Northern Region						
Williston Basin	3,166.8	3,076.5	90.3	5,779.0	6,413.2	(634.2)
Pinedale	—	137.7	(137.7)	—	280.7	(280.7)
Uinta Basin	168.6	162.5	6.1	320.3	328.6	(8.3)
Other Northern	19.2	37.3	(18.1)	57.0	64.2	(7.2)
Southern Region						
Permian Basin	3,207.2	1,449.6	1,757.6	5,366.3	2,451.3	2,915.0
Haynesville/Cotton Valley	4.5	5.7	(1.2)	10.3	12.9	(2.6)
Other Southern	1.3	1.0	0.3	8.7	2.1	6.6
Total production	6,567.6	4,870.3	1,697.3	11,541.6	9,553.0	1,988.6
Average field-level oil prices (per bbl)						
Northern Region	$64.99	$43.86	$21.13	$63.14	$45.27	$17.87
Southern Region	$59.30	$45.49	$13.81	$59.51	$47.39	$12.12
Average field-level price	$62.21	$44.35	$17.86	$61.45	$45.82	$15.63
Commodity derivative impact	(7.91)	2.37	(10.28)	(8.34)	0.99	(9.33)
Net realized price	$54.30	$46.72	$7.58	$53.11	$46.81	$6.30

Oil and condensate revenues increased $192.5 million, or 89%, in the second quarter of 2018 compared to the second quarter of 2017, due to higher average field-level prices and higher oil and condensate production volumes. Average field-level oil prices increased 40% in the second quarter of 2018 compared to the second quarter of 2017 primarily driven by an increase in average NYMEX-WTI oil prices for the comparable periods. The 35% increase in production volumes was driven by increases in the Permian Basin due to increased drilling activity, partially offset by a loss of volumes from Pinedale as a result of the Pinedale Divestiture.

Oil and condensate revenues increased $271.5 million, or 62%, in the first half of 2018 compared to the first half of 2017, due to higher average field-level prices and higher oil and condensate production volumes. Average field-level oil prices increased 34% in the first half of 2018 compared to the first half of 2017 primarily driven by an increase in average NYMEX-WTI oil prices for the comparable periods. The 21% increase in production volumes was driven by an increase in the Permian Basin due to increased drilling activity, partially offset by decrease in production in the Williston Basin and a loss of volumes from Pinedale as a result of the Pinedale Divestiture.

Gas Volumes and Prices

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
Gas production volumes (Bcf)						
Northern Region						
Williston Basin	3.8	4.1	(0.3)	7.2	8.1	(0.9)
Pinedale	—	17.6	(17.6)	—	36.1	(36.1)
Uinta Basin	3.7	4.2	(0.5)	7.4	8.8	(1.4)
Other Northern	0.1	1.8	(1.7)	0.5	3.6	(3.1)
Southern Region						
Permian Basin	2.1	1.3	0.8	4.0	2.5	1.5
Haynesville/Cotton Valley	28.5	16.7	11.8	54.2	28.9	25.3
Other Southern	0.1	0.1	—	0.1	0.1	—
Total production	38.3	45.8	(7.5)	73.4	88.1	(14.7)
Average field-level gas prices (per Mcf)						
Northern Region	$2.17	$2.86	$(0.69)	$2.48	$3.05	$(0.57)
Southern Region	$2.65	$3.03	$(0.38)	$2.78	$3.05	$(0.27)
Average field-level price	$2.55	$2.93	$(0.38)	$2.72	$3.05	$(0.33)
Commodity derivative impact	0.17	(0.11)	0.28	0.10	(0.22)	0.32
Net realized price	$2.72	$2.82	$(0.10)	$2.82	$2.83	$(0.01)

Gas revenues decreased $36.4 million, or 27%, in the second quarter of 2018 compared to the second quarter of 2017, due to lower gas production volumes and lower average field-level prices. Production volumes decreased primarily due to the Pinedale Divestiture and divestitures in the Other Northern area. These production decreases were partially offset by an increase in production in the second quarter of 2018 in Haynesville/Cotton Valley. The 71% increase in gas production in Haynesville/Cotton Valley was due to the continued refracturing and drilling programs. Average field-level gas prices decreased 13% in the second quarter of 2018 compared to the second quarter of 2017, primarily driven by a decrease in average NYMEX-HH gas prices for the comparable periods.

Gas revenues decreased $68.9 million, or 26%, in the first half of 2018 compared to the first half of 2017, due to lower gas production volumes and lower average field-level prices. Production volumes decreased primarily due to the Pinedale Divestiture, divestitures in the Other Northern area and decreases in the Uinta Basin due to normal decline, partially offset by two new well completions in the Uinta Basin late in the first quarter of 2018. These production decreases were partially offset by an 87% increase in gas production in the first half of 2018 in Haynesville/Cotton Valley. The increase in gas production in Haynesville/Cotton Valley was due to the continued refracturing and drilling programs. Average field-level gas prices decreased 11% in the first half of 2018 compared to the first half of 2017, primarily driven by a decrease in average NYMEX-HH gas prices for the comparable periods.

NGL Volumes and Prices

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
NGL production volumes (Mbbl)						
Northern Region						
Williston Basin	666.7	822.7	(156.0)	1,218.1	1,645.9	(427.8)
Pinedale	—	231.5	(231.5)	—	524.0	(524.0)
Uinta Basin	34.9	33.6	1.3	71.2	75.0	(3.8)
Other Northern	2.4	3.9	(1.5)	5.7	8.2	(2.5)
Southern Region						
Permian Basin	448.4	259.8	188.6	761.3	447.6	313.7
Haynesville/Cotton Valley	0.2	2.7	(2.5)	0.3	8.7	(8.4)
Other Southern	0.2	0.7	(0.5)	0.6	0.9	(0.3)
Total production	1,152.8	1,354.9	(202.1)	2,057.2	2,710.3	(653.1)
Average field-level NGL prices (per bbl)						
Northern Region	$23.44	$17.37	$6.07	$23.05	$19.82	$3.23
Southern Region	$21.91	$14.77	$7.14	$21.49	$15.62	$5.87
Average field-level price	$22.84	$16.86	$5.98	$22.47	$19.11	$3.36
Commodity derivative impact	—	—	—	—	—	—
Net realized price	$22.84	$16.86	$5.98	$22.47	$19.11	$3.36

NGL production volumes and revenues represent the sale of liquids derived from the processing of QEP's natural gas production. NGL revenues increased $3.6 million, or 16%, during the second quarter of 2018 compared to the second quarter of 2017, due to higher average field-level prices, partially offset by lower NGL production volumes. The 35% increase in NGL prices during the second quarter of 2018 compared to the second quarter of 2017, was primarily driven by an increase in propane, ethane and other NGL component prices. The increase in price was partially offset by a 15% decrease in NGL production volumes. The decrease was primarily driven by a loss of volumes from Pinedale due to the Pinedale Divestiture and a production decrease in the Williston Basin due to declining gas volumes and a lower amount of ethane allocated to us by the midstream provider in the second quarter of 2018 compared to the second quarter of 2017. These production decreases were partially offset by an increase in production in the Permian Basin due to increased drilling activity.

NGL revenues decreased $5.6 million, or 11%, during the first half of 2018 compared to the first half of 2017, due to lower NGL production volumes, partially offset by higher average field-level prices. The 24% decrease in NGL production volumes was primarily driven by a loss of volumes from Pinedale due to the Pinedale Divestiture and production decreases in the Williston Basin due to declining gas volumes and a lower amount of ethane allocated to us by the midstream provider in the first half of 2018 compared to the first half 2017. These decreases were partially offset by an increase in production in the Permian Basin due to increased drilling activity. The overall decrease in production volumes was partially offset by an 18% increase in NGL prices during the first half of 2018 compared to the first half of 2017, primarily driven by an increase in propane, ethane and other NGL component prices.

Resale Margin and Storage Activity

QEP purchases and resells oil and gas primarily to mitigate losses on unutilized capacity related to firm transportation commitments and storage activities. The following table is a summary of QEP's financial results from its resale activities.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
	(in millions)					
Purchased oil and gas sales	$9.1	$8.0	$ 1.1	$23.2	$38.9	$(15.7)
Purchased oil and gas expense	(9.8)	(9.1)	(0.7)	(25.3)	(38.5)	13.2
Realized gains (losses) on gas storage derivative contracts	0.1	—	0.1	0.3	(0.2)	0.5
Resale margin	$(0.6)	$(1.1)	$ 0.5	$(1.8)	$0.2	$(2.0)

Purchased oil and gas sales and expense increased during the second quarter of 2018 compared to second quarter of 2017, due to an increase in resale volumes to meet Northern Region gas transportation commitments retained in the various divestitures partially offset by lower resale volumes needed to meet gas transportation commitments in the Southern Region due to increased production.

Purchased oil and gas sales and expense decreased during the first half of 2018 compared to first half of 2017, due to lower resale volumes needed to meet gas transportation commitments in the Southern Region due to increased production.

Operating Expenses

The following table presents QEP production costs and production costs on a per unit of production basis:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Change	2018	2017	Change
	(in millions)					
Lease operating expense	$66.5	$70.0	$(3.5)	$139.0	$139.2	$(0.2)
Adjusted transportation and processing costs[1]	43.6	72.2	(28.6)	90.3	142.4	(52.1)
Production and property taxes	37.6	28.5	9.1	66.5	57.6	8.9
Total production costs	$147.7	$170.7	$(23.0)	$295.8	$339.2	$(43.4)
	(per Boe)					
Lease operating expense	$4.71	$5.05	$(0.34)	$5.38	$5.17	$0.21
Adjusted transportation and processing costs[1]	3.09	5.21	(2.12)	3.49	5.28	(1.79)
Production and property taxes	2.66	2.06	0.60	2.57	2.14	0.43
Total production costs	$10.46	$12.32	$(1.86)	$11.44	$12.59	$(1.15)

(1) Below are reconciliations of transportation and processing costs (a GAAP measure) as presented on the Condensed Consolidated Statements of Operations and on a unit of production basis to adjusted transportation and processing costs. Adjusted transportation and processing costs includes transportation and processing costs that are reflected as part of "Oil and condensate, gas and NGL sales" on the Condensed Consolidated Statements of Operations. Management adds these costs together with transportation and processing costs reflected on the Condensed Consolidated Statements of Operations to reflect the total operating costs associated with its production. Management believes that this non-GAAP measure is useful supplemental information for investors as it is reflective of the total production costs required to operate the wells for the period and is a more comparable measure to the operating costs of its peers. This non-GAAP measure should be considered by the reader in addition to but not instead of, the financial statements prepared in accordance with GAAP. Refer to Note 2 – Revenue in Part 1, Item I of this Quarterly Report on Form 10-Q.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017[1]	Change	2018	2017[1]	Change
	(in millions)					
Adjusted transportation and processing costs	$43.6	$ 72.2	$(28.6)	$90.3	$142.4	$(52.1)
Transportation and processing costs deducted from oil and condensate, gas and NGL sales	(12.4)	—	(12.4)	(25.1)	—	(25.1)
Transportation and processing costs, as presented	$31.2	$ 72.2	$(41.0)	$65.2	$142.4	$(77.2)
	(per Boe)					
Adjusted transportation and processing costs	$3.09	$ 5.21	$(2.12)	$3.49	$5.28	$(1.79)
Transportation and processing costs deducted from oil and condensate, gas and NGL sales	(0.88)	—	(0.88)	(0.97)	—	(0.97)
Transportation and processing costs, as presented	$2.21	$ 5.21	$(3.00)	$2.52	$5.28	$(2.76)

(1) Prior period amounts have not been adjusted under the modified retrospective method for the new revenue recognition rule. Refer to Note 2 – Revenue in Part 1, Item 1 of this Quarterly Report on Form 10-Q.

Lease operating expense (LOE). QEP's LOE decreased $3.5 million, or 5%, in the second quarter of 2018 compared to the second quarter of 2017 due to the Pinedale Divestiture. Excluding Pinedale, LOE increased $5.0 million, primarily driven by increases in the Permian Basin due to the 2017 Permian Basin Acquisition, and increased maintenance and repairs, power and fuel and chemical expenses.

During the second quarter of 2018, LOE decreased $0.34 per Boe, or 7%, compared with the second quarter of 2017, but was down 19% excluding the loss of lower LOE production in Pinedale as a result of the Pinedale Divestiture. The 19% per BOE decrease related to lower cost production from the recent horizontal well completions in the Permian Basin and Haynesville/Cotton Valley.

QEP's LOE decreased $0.2 million in the first half of 2018 compared to the first half of 2017, due to the Pinedale Divestiture. Excluding Pinedale, LOE increased $17.1 million, primarily driven by increases in the Permian Basin, Williston Basin and Haynesville/Cotton Valley. The Permian Basin increase relates to the 2017 Permian Basin Acquisition, and increased maintenance and repairs, power and fuel and chemical expenses. The Williston Basin increase was due to increased power and fuel, compression and labor costs. The Haynesville/Cotton Valley increase was due to higher labor and water disposal costs.

During the first half of 2018, LOE increased $0.21 per Boe, or 4%, compared with the first half of 2017, due to the loss of lower LOE production in Pinedale as a result of the Pinedale Divestiture. Excluding the Pinedale Divestiture, LOE per Boe was down 12% primarily due to lower cost production from the recent horizontal well completions in the Permian Basin and Haynesville/Cotton Valley partially offset by an increase in our Williston Basin rate due to increased expenses on declining production volumes.

Adjusted transportation and processing costs. Adjusted transportation and processing costs decreased $28.6 million, or 40%, during the second quarter of 2018 compared to the second quarter of 2017. The decrease in expense was primarily attributable to the Pinedale Divestiture.

During the second quarter of 2018, adjusted transportation and processing costs decreased $2.12 per Boe, or 41%, compared to the second quarter of 2017, due to the Pinedale Divestiture, which had higher adjusted transportation and processing costs per Boe. Excluding the Pinedale Divestiture, adjusted transportation and processing costs per Boe were down 28% due to decreases in both Haynesville/Cotton Valley and the Permian Basin during the second quarter of 2018 compared to the second quarter of 2017. The cost per Boe decreased in Haynesville/Cotton Valley due to increased production that increased utilization of the Company's firm transportation commitments on interstate pipelines. The cost per Boe decrease in the Permian Basin was driven by increased production and associated throughput under lower cost transportation and processing contracts.

Adjusted transportation and processing costs decreased $52.1 million, or 37%, during the first half of 2018 compared to the first half of 2017. The decrease in expense was primarily attributable to the Pinedale Divestiture.

During the first half of 2018, adjusted transportation and processing costs decreased $1.79 per Boe, or 34%, compared to the first half of 2017, due to the Pinedale Divestiture, which had higher adjusted transportation and processing costs per Boe. Excluding the Pinedale Divestiture, adjusted transportation and processing costs per Boe were down 23% due to a decrease in Haynesville/Cotton Valley and the Permian Basin during the first half of 2018 compared to the first half of 2017. The cost per Boe decreased in Haynesville/Cotton Valley due to increased production that increased utilization of the Company's firm transportation commitments on interstate pipelines. The cost per Boe decrease in the Permian Basin was driven by increased production and associated throughput under lower cost transportation and processing contracts.

General and administrative (G&A) expense. During the second quarter of 2018, G&A expense increased $24.5 million, or 78%, compared to the second quarter of 2017. During the second quarter of 2018, QEP incurred $9.5 million in restructuring costs associated with the implementation of our Strategic Initiatives, of which $6.3 million relates to retention expense, $1.7 million of termination benefits, $1.2 million of accelerated share-based compensation and $0.3 million related to office lease termination costs (refer to Note 8 – Restructuring, in Item I of Part I of this Quarterly Report on Form 10-Q). In addition to these restructuring related costs, QEP recognized an $11.7 million increase in share-based compensation and changes in the mark-to-market value of the Deferred Compensation Wrap Plan and a $4.5 million increase related to reduced overhead recoveries, primarily associated with our Pinedale Divestiture.

During the first half of 2018, G&A expense increased $51.0 million, or 79%, compared to the first half of 2017. During the first half of 2018, QEP incurred $17.4 million in restructuring costs associated with the implementation of our Strategic Initiatives, of which $8.0 million relates to retention expense, $5.1 million of termination benefits $4.0 million of accelerated share-based compensation and $0.3 million related to office lease termination costs (refer to Note 8 – Restructuring, in Item I of Part I of this Quarterly Report on Form 10-Q). In addition to these restructuring related costs, QEP recognized a $16.7 million increase in share-based compensation and changes in the mark-to-market value of the Deferred Compensation Wrap Plan, a $8.2 million increase related to reduced overhead recoveries, primarily associated with our Pinedale Divestiture and a $5.0 million increase in legal and outside expenses related to our Strategic Initiatives.

Production and property taxes. In most states in which QEP operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume-based. Production and property taxes increased $9.1 million, or 32%, in the second quarter of 2018 compared to the second quarter of 2017, primarily due to increased oil pricing and increased oil and condensate production in the Williston and Permian basins, and increased gas production in Haynesville/Cotton Valley, partially offset by the Pinedale Divestiture.

During the second quarter of 2018, production and property taxes increased $0.60 per Boe, or 29%, compared to the second quarter of 2017, but increased 63% excluding the Pinedale Divestiture. The 63% increase was due to an increase in average field-level equivalent prices in the Permian and Williston basins offset by a lower rate per Boe in Haynesville/Cotton Valley due to lower non-operated ad valorem charges and franchise taxes per Boe.

Production and property taxes increased $8.9 million, or 15%, in the first half of 2018 compared to the first half of 2017, primarily due to increased oil pricing and increased oil and condensate production in the Permian Basin, and increased gas production in Haynesville/Cotton Valley, partially offset by the Pinedale Divestiture.

During the first half of 2018, production and property taxes increased $0.43 per Boe, or 20%, compared to the first half of 2017, but increased 57% excluding the Pinedale Divestiture. The 57% increase was due to an increase in average field-level equivalent prices in the Permian and Williston basins, partially offset by a lower rate per Boe in Haynesville/Cotton Valley due to lower non-operated ad valorem charges and franchise taxes per Boe.

Depreciation, depletion and amortization (DD&A). DD&A expense increased $50.7 million in the second quarter of 2018 compared to the second quarter of 2017, primarily due to increased production and a higher DD&A rate in the Permian Basin and Haynesville/Cotton Valley, partially offset by lower DD&A due to the Pinedale Divestiture.

DD&A expense increased $55.4 million in the first half of 2018 compared to the first half of 2017, primarily due to increased production and a higher DD&A rate in the Permian Basin and Haynesville/Cotton Valley, partially offset by lower DD&A due to the Pinedale Divestiture.

Impairment expense. During the second quarter of 2018, QEP recorded impairment charges of $403.7 million, which were primarily due to the impairment of proved and unproved properties related to the Uinta Basin Divestiture.

During the first half of 2018, QEP recorded impairment charges of $404.4 million, of which $402.8 million of proved and unproved properties impairment was triggered by the Uinta Basin Divestiture and $1.6 million was related to expiring leaseholds on unproved properties and impairment of proved properties related to a divestiture in the Other Northern area.

Net gain (loss) from asset sales, inclusive of restructuring costs. During the second quarter of 2018, QEP recognized a loss on the sale of assets of $3.9 million, primarily related to a pre-tax loss of $1.9 million related to estimated restructuring costs associated with the Uinta Basin Divestiture (refer to Note 8 – Restructuring, in Item I of Part I of

this Quarterly Report on Form 10-Q for more information). In addition, QEP recognized a pre-tax loss of $2.0 million related to the divestiture of properties outside our main operating areas in the Uinta Basin and the Other Northern area, and an underground gas storage facility. During the second quarter of 2017, QEP recognized a gain on the sale of assets of $19.8 million related to the sale of non-core Other Northern properties.

During the first half of 2018, QEP recognized a loss on the sale of assets of $0.4 million primarily comprised of $1.9 million of estimated restructuring costs associated with the Uinta Basin Divestiture (refer to Note 8 – Restructuring, in Item I of Part I of this Quarterly Report on Form 10-Q for more information) partially offset by a net pre-tax gain on sale of assets of $1.5 million related to the divestiture of properties outside our main operating areas in the Uinta Basin, Pinedale and the Other Northern area, and an underground gas storage facility. During the first half of 2017, QEP recognized a gain on the sale of assets of $19.8 million related to the sale of non-core Other Northern properties.

Non-operating Expenses

Realized and unrealized gains (losses) on derivative contracts. Gains and losses on derivative contracts are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts, which are marked-to-market each quarter. During the second quarter of 2018, losses on commodity derivative contracts were $79.1 million, of which $45.5 million were realized losses and $33.6 million were unrealized losses. During the second quarter of 2017, gains on commodity derivative contracts were $106.7 million, of which $100.3 million were unrealized gains and $6.4 million were realized gains.

During the first half of 2018, losses on commodity derivative contracts were $132.3 million of which $88.7 million were realized losses and $43.6 million were unrealized losses. During the first half of 2017, gains on commodity derivative contracts were $267.6 million, of which $277.6 million were unrealized gains and $10.0 million were realized losses.

Interest expense. Interest expense increased $3.3 million, or 9%, during the second quarter of 2018 compared to the second quarter of 2017. The increase during the second quarter of 2018 was primarily related to increased interest on the borrowings under the credit facility partially offset by lower interest rates on senior notes.

Interest expense increased $4.5 million, or 7%, during the first half of 2018 compared to the first half of 2017. The increase during the first half of 2018 was primarily related to increased interest on the borrowings under the credit facility partially offset by lower interest rates on senior notes.

Income tax (provision) benefit. Income tax benefit increased $133.5 million during the second quarter of 2018 compared to the second quarter of 2017. The increase in benefit was the result of a net loss during the second quarter of 2018 compared to net income during the second quarter of 2017 and a lower combined effective federal and state income tax rate of 24.0% during the second quarter of 2018 compared to a rate of 37.6% during the second quarter of 2017. The decrease in income tax rate was primarily the result of the Tax Cuts and Job Act (H.R. 1) signed into law in December 2017.

Income tax benefit increased $193.0 million during the first half of 2018 compared to the first half of 2017. The increase in benefit was the result of a net loss during the first half of 2018 compared to net income during the first half of 2017 and a lower combined effective federal and state income tax rate of 23.6% during the first half of 2018 compared to a rate of 37.3% during the first half of 2017. The decrease in income tax rate was primarily the result of the Tax Cuts and Job Act (H.R. 1) signed into law in December 2017.

LIQUIDITY AND CAPITAL RESOURCES

QEP strives to maintain sufficient liquidity to ensure financial flexibility, withstand commodity price volatility and fund its development projects, operations, capital expenditures and Strategic Initiatives. The Company utilizes derivative contracts to reduce the financial impact of commodity price volatility and provide a level of certainty to the Company's cash flows. QEP generally funds its operations and planned capital expenditures with cash flow from its operating activities, cash on hand and borrowings under its revolving credit facility. The Company expects that cash flows from its operating activities and borrowings under its revolving credit facility will be sufficient to fund its operations and capital expenditures during the next 12 months and the foreseeable future.

QEP also periodically accesses debt and equity markets and sells properties. In the first half of 2018, QEP engaged advisors to assist with the divestiture of its Williston Basin and Uinta Basin assets and provided data for potential buyers to evaluate. If the marketing of these assets is successful, the Company plans to use the proceeds to fund on-going operations, reduce debt, repurchase shares and for general corporate purposes.

The Company estimates, that as of June 30, 2018, it could incur additional indebtedness of approximately $675.0 million and be in compliance with the covenants contained in its revolving credit facility. To the extent actual operating results, realized commodity prices or uses of cash differ from the Company's assumptions, QEP's liquidity could be adversely affected.

Credit Facility

QEP's revolving credit facility, which matures, subject to satisfaction of certain conditions, in September 2022, provides for loan commitments of $1.25 billion. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit agreement contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a net funded debt to capitalization ratio that may not exceed 60%, (ii) a leverage ratio under which net funded debt may not exceed 4.00 times consolidated EBITDA (as defined in the credit agreement) commencing with the fiscal quarter ending March 31, 2018, through the fiscal quarter ending December 31, 2018, and 3.75 times thereafter, and (iii) during a ratings trigger period (as defined), a present value coverage ratio under which the present value of the Company's proved reserves must exceed net funded debt by 1.25 times at any time prior to January 1, 2019, must exceed net funded debt by 1.40 times commencing on January 1, 2019 through December 31, 2019, and must exceed net funded debt by 1.50 times at any time on or after January 1, 2020. The Company is currently not subject to the present value coverage ratio. As of June 30, 2018 and 2017, QEP was in compliance with the covenants under the credit agreement.

During the six months ended June 30, 2018, QEP's weighted-average interest rate on borrowings from its credit facility was 4.22%. As of June 30, 2018, QEP had $575.0 million of borrowings outstanding and $0.3 million in letters of credit outstanding under the credit facility. As of December 31, 2017, QEP had $89.0 million of borrowings outstanding and $1.0 million in letters of credit outstanding under the credit facility. As of July 20, 2018, QEP had $525.0 million of borrowings outstanding, had $0.3 million in letters of credit outstanding under the credit facility and was in compliance with the covenants under the credit agreement.

Senior Notes

The Company's senior notes outstanding as of June 30, 2018, totaled $2,099.3 million principal amount and are comprised of five issuances as follows:

- $51.7 million 6.80% Senior Notes due March 2020;
- $397.6 million 6.875% Senior Notes due March 2021;
- $500.0 million 5.375% Senior Notes due October 2022;
- $650.0 million 5.25% Senior Notes due May 2023; and
- $500.0 million 5.625% Senior Notes due March 2026.

Cash Flow from Operating Activities

Cash flows from operating activities are primarily affected by oil and condensate, gas and NGL production volumes and commodity prices (including the effects of settlements of the Company's derivative contracts) and by changes in working capital. QEP typically enters into commodity derivative transactions covering a substantial, but varying, portion of its anticipated future oil and gas production for the next 12 to 24 months.

Net cash provided by (used in) operating activities is presented below:

	Six Months Ended June 30,		
	2018	2017	Change
	(in millions)		
Net income (loss)	$(389.6)	$122.3	$(511.9)
Non-cash adjustments to net income (loss)	792.2	163.0	629.2
Changes in operating assets and liabilities	(25.7)	10.7	(36.4)

Net cash provided by (used in) operating activities	$376.9	$296.0	$80.9

Net cash provided by operating activities was $376.9 million during the first half of 2018, which included $389.6 million of net loss, $792.2 million of non-cash adjustments to the net loss and $25.7 million in changes in operating assets and liabilities. Non-cash adjustments to the net loss of $792.2 million primarily included DD&A expense of $438.7 million, $404.4 million of impairment expense, $43.6 million of unrealized losses on derivative contracts, and $23.4 million of share-based compensation expense, partially offset by $120.5 million of deferred income taxes. The decrease in changes in operating assets and liabilities of $25.7 million primarily resulted from an increase in accounts receivable of $32.6 million and a decrease in other long-term liabilities of $9.6 million, partially offset by an increase in interest payable of $6.7 million and an increase in accounts payable and accrued expenses of $3.2 million.

Net cash provided by operating activities was $296.0 million during the first half of 2017, which included $122.3 million of net income, $163.0 million of non-cash adjustments to net income and a $10.7 million increase in changes in operating assets and liabilities. Non-cash adjustments to net income of $163.0 million primarily included DD&A expense of $383.3 million and $67.2 million of deferred income taxes, partially offset by unrealized gains on derivative contracts of $277.6 million. The increase in changes in operating assets and liabilities of $10.7 million primarily resulted from a decrease in accounts receivable of $27.4 million, partially offset by a decrease in accounts payable and accrued expenses of $7.8 million and a decrease in the ARO liability of $2.0 million.

Cash Flow from Investing Activities

A comparison of capital expenditures for the first half of 2018 and 2017, are presented in the table below:

	Six Months Ended June 30,		
	2018	2017	Change
	(in millions)		
Property acquisitions	$45.1	$76.6	$(31.5)
Property, plant and equipment capital expenditures	784.5	520.3	264.2
Total accrued capital expenditures	829.6	596.9	232.7
Change in accruals and other non-cash adjustments	(20.2)	(42.4)	22.2
Total cash capital expenditures	$809.4	$554.5	$254.9

In the first half of 2018, on an accrual basis, the Company invested $784.5 million on property, plant and equipment capital expenditures (which excludes property acquisitions), an increase of $264.2 million compared to the first half of 2017. In the first half of 2018, QEP's significant capital expenditures included $498.9 million in the Permian Basin (including midstream infrastructure of $38.3 million, primarily related to fresh water supply, produced water gathering, salt water disposal and oil and gas gathering), $157.8 million in the Williston Basin, $120.6 million in Haynesville/Cotton Valley (including midstream infrastructure of $7.5 million, primarily related to gas gathering) and $4.5 million in the Uinta Basin. In addition, in the first half of 2018, QEP acquired various oil and gas properties, primarily proved and unproved leasehold acreage in the Permian Basin for an aggregate purchase price of $45.1 million, of which $37.5 million was related to the 2017 Permian Basin Acquisition.

In the first half of 2017, on an accrual basis, the Company invested $520.3 million on property, plant and equipment capital expenditures (which excludes property acquisitions), including $297.7 million in the Permian Basin, $128.1 million in the Williston Basin, $72.2 million in Haynesville/Cotton Valley and $12.3 million in Pinedale. In addition, during the first half of 2017, QEP acquired various oil and gas properties, primarily proved and unproved leaseholds and additional surface acreage primarily in the Permian Basin, for an aggregate purchase price of $76.6 million.

The mid-point of our 2018 forecasted capital expenditures (excluding property acquisitions) is $1,120.0 million. QEP intends to fund capital expenditures (excluding property acquisitions) with cash flow from operating activities and borrowings under the credit facility. The aggregate levels of capital expenditures for 2018 and the allocation of those expenditures are dependent on a variety of factors, including drilling results, oil, gas and NGL prices, industry conditions, the extent to which properties or working interests are acquired, the availability of capital resources to fund the expenditures and changes in management's business assessments as to where QEP's capital can be most profitably deployed. Accordingly, the actual levels of capital expenditures and the allocation of those expenditures may vary materially from QEP's estimates.

Cash Flow from Financing Activities

In the first half of 2018, net cash provided by financing activities was $386.4 million compared to net cash used in financing activities of $8.0 million in the first half of 2017. During the first half of 2018, QEP had borrowings from the credit facility of $2,029.5 million and repayments on its credit facility of $1,543.5 million. In addition, QEP used $58.4 million of cash to repurchase common stock under the Company's share repurchase program and had treasury stock repurchases of $5.9 million related to the settlement of income tax and related benefit withholding obligations arising from the vesting of restricted share grants. QEP had a decrease in checks outstanding in excess of cash balances of $35.5 million. During the first half of 2017, QEP had treasury stock repurchases of $6.4 million, a decrease in long-term debt issuance costs paid of $1.1 million and a decrease in checks outstanding in excess of cash balances of $0.5 million.

As of June 30, 2018, long-term debt consisted of $2,649.4 million, of which $2,099.3 million is senior notes, $575.0 million outstanding on the credit facility and a $24.9 million reduction related to the net original issue discount and unamortized debt issuance costs.

Significant Accounting Policies

Refer to Note 2 – Revenue in Part 1, Item 1 of this Quarterly Report on Form 10-Q for changes in QEP's revenue recognition policy as a result of the adoption of ASC Topic 606, effective January 1, 2018.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

QEP's primary market risks arise from changes in the market price for oil, gas and NGL and volatility in interest rates. These risks can affect revenues and cash flows from operating, investing and financing activities. Commodity prices have historically been volatile and are subject to wide fluctuations in response to relatively minor changes in supply and demand. If commodity prices fluctuate significantly, revenues and cash flow may significantly decrease or increase. QEP has long-term contracts for pipeline capacity and is obligated to pay for transportation services with no guarantee that it also will be able to fully utilize the contractual capacity of these transportation commitments. In addition, additional non-cash impairment expense of the Company's oil and gas properties may be required if future oil and gas commodity prices experience a significant decline. Furthermore, the Company's revolving credit facility has a floating interest rate, which exposes QEP to interest rate risk if QEP has borrowings outstanding. To partially manage the Company's exposure to these risks, QEP enters into commodity derivative contracts in the form of fixed-price and basis swaps and collars to manage commodity price risk and periodically enters into interest rate swaps to manage interest rate risk.

Commodity Price Risk Management

QEP uses commodity derivative instruments in the normal course of business to reduce the risk of adverse commodity price movements. However, these arrangements typically limit future gains from favorable price movements. The types of commodity derivative instruments currently utilized by the Company are fixed-price and basis swaps and collars. The volume of commodity derivative instruments utilized by the Company may vary from year to year based on QEP's forecasted production. The Company's current derivative instruments do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. As of June 30, 2018, QEP held commodity price derivative contracts totaling 19.3 million barrels of oil and 97.5 million MMBtu of gas.

The following tables present QEP's volumes and average prices for its derivative positions as of July 20, 2018. Refer to Note 7 – Derivative Contracts in Part 1, Item 1 of this Quarterly Report on Form 10-Q for open derivative positions as of June 30, 2018.

Production Commodity Derivative Swaps

Year	Index	Total Volumes (in millions)	Average Swap Price per Unit
Oil sales		(bbls)	($/bbl)
2018	NYMEX WTI	8.3	$ 52.46
2019	NYMEX WTI	9.5	$ 52.66
2020	NYMEX WTI	1.8	$ 60.77
Gas sales		(MMBtu)	($/MMBtu)
2018	NYMEX HH	44.1	$ 3.00
2019	NYMEX HH	43.8	$ 2.86

Production Commodity Derivative Basis Swaps

Year	Index	Basis	Total Volumes (in millions)	Weighted-Average Differential
Oil sales			(bbls)	($/bbl)
2018	NYMEX WTI	Argus WTI Midland	4.6	$ (0.99)
2018	NYMEX WTI	Argus WTI Houston	0.2	$ 6.30
2019	NYMEX WTI	Argus WTI Midland	4.7	$ (0.77)
2019	NYMEX WTI	Argus WTI Houston	0.4	$ 4.35
2020	NYMEX WTI	Argus WTI Midland	1.5	$ (1.01)
Gas sales			(MMBtu)	($/MMBtu)
2018	NYMEX HH	IFNPCR	3.1	$ (0.16)

In conjunction with the execution of the purchase and sale agreement for the Uinta Basin Divestiture, QEP, at the request of the buyer, entered into the derivative contracts listed below. Upon the closing of the sale in the third quarter of 2018, the derivative contracts will be novated to the buyer. Refer to Note 3 – Acquisitions and Divestitures, in Item I of Part I of this Quarterly Report on Form 10-Q for more information. The following tables present QEP's volumes and average prices for the Uinta Basin Divestiture derivative positions as of July 20, 2018.

Uinta Basin Divestiture Commodity Derivative Swaps

Year	Index	Total Volumes	Average Swap Price per Unit
Oil sales		(in millions) (bbls)	($/bbl)
2018	NYMEX WTI	0.1	$ 68.55
2019	NYMEX WTI	0.5	$ 65.30
2020	NYMEX WTI	0.6	$ 61.20
2021	NYMEX WTI	0.6	$ 58.50
2022	NYMEX WTI	0.4	$ 56.15
2023	NYMEX WTI	0.2	$ 55.00
Gas sales		(MMBtu)	($/MMBtu)
2018	NYMEX HH	2.9	$ 2.86
2019	NYMEX HH	13.4	$ 2.74
2020	NYMEX HH	20.2	$ 2.63
2021	NYMEX HH	19.3	$ 2.59
2022	NYMEX HH	8.7	$ 2.61
2023	NYMEX HH	5.4	$ 2.68

Uinta Basin Divestiture Commodity Derivative Basis Swaps

Year	Index	Basis	Total Volumes	Weighted-Average Differential
Gas sales			(MMBtu)	($/MMBtu)
2018	NYMEX HH	IFNPCR	2.9	$ (0.63)
2019	NYMEX HH	IFNPCR	13.4	$ (0.77)
2020	NYMEX HH	IFNPCR	20.2	$ (0.77)

Changes in the fair value of derivative contracts from December 31, 2017 to June 30, 2018, are presented below:

	Commodity derivative contracts (in millions)
Net fair value of oil and gas derivative contracts outstanding at December 31, 2017	$ (131.9)
Contracts settled	88.7
Change in oil and gas prices on futures markets	61.2
Contracts added	(193.4)
Net fair value of oil and gas derivative contracts outstanding at June 30, 2018	$ (175.4)

The following table shows the sensitivity of the fair value of oil and gas derivative contracts to changes in the market price of oil, gas and basis differentials:

	June 30, 2018 (in millions)
Net fair value – asset (liability)	$ (175.4)
Fair value if market prices of oil, gas and basis differentials decline by 10%	$ (157.8)

Fair value if market prices of oil, gas and basis differentials increase by 10%	$ (192.9)

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $17.5 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $17.6 million as of June 30, 2018. However, a gain or loss eventually would be offset by the actual sales value of the physical production covered by the derivative instruments. For additional information regarding the Company's commodity derivative transactions, refer to Note 7 – Derivative Contracts in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Interest Rate Risk Management

The Company's ability to borrow and the rates offered by lenders can be adversely affected by illiquid credit markets and the Company's credit rating, as described in the risk factors in Item 1A of Part I of its 2017 Form 10-K. The Company's revolving credit facility has a floating interest rate, which exposes QEP to interest rate risk if QEP has borrowings outstanding. At June 30, 2018, the Company had $575.0 million of borrowings outstanding under its revolving credit facility. If interest rates were to increase or decrease 10% during the six months ended June 30, 2018, at our average level of borrowing for those same periods, the Company's interest expense would increase or decrease by $0.8 million for the three months ended June 30, 2018, or approximately 1% of total interest expense.

The remaining $2,099.3 million of the Company's debt is senior notes with fixed interest rates; therefore, it is not affected by interest rate movements. For additional information regarding the Company's debt instruments, refer to Note 9 – Debt, in Item I of Part I of this Quarterly Report on Form 10-Q.

Forward-Looking Statements

The quarterly report contains information that includes or is based upon "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements give expectations or forecasts of future events. You can identify these statements by the fact that they do not relate strictly to historical or current facts. We use words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," and other words and terms of similar meaning in connection with a discussion of future operating or financial performance. Forward-looking statements include statements relating to, among other things:

- our Strategic Initiatives to transition to a pure-play Permian Basin company, including the use of proceeds from such asset sales;
- reducing operating and per well drilling costs and managing liquidity;
- plans to grow oil and condensate production in the Permian Basin;
- drilling and completion plans and strategies;
- acquiring acreage in the Permian Basin to add development opportunities and facilitate the drilling of long lateral wells;
- estimated future payments to reimburse the buyer in the Pinedale Divestiture for certain deficiency charges related to the gas processing and NGL transportation and fractionation contracts;
- future development costs and funding for such development costs;
- the conditions impacting the timing and amount of share repurchases under our share repurchase program;
- the usefulness of non-GAAP financial measures;
- our inventory of drilling locations;
- ability of our inventory locations to provide a solid base for growth in production and reserves;
- evaluation of potential acquisitions and divestiture opportunities;
- our balance sheet and liquidity position allowing us to grow oil production in the Permian Basin and achieve our Strategic Initiatives;
- amount and allocation of forecasted capital expenditures (excluding property acquisitions) and, plans for funding operations and capital investments;
- potential for asset impairments, including estimated impairment amounts, and factors impacting impairment amounts;
- fair value estimates and related assumptions and assessment of the sensitivity of changes in assumptions, and critical accounting estimates, including estimated asset retirement obligations and fair value estimates of stock options;
- impact of global geopolitical and macroeconomic events;
- plans regarding derivative contracts, including the volumes utilized, and the anticipated benefits derived there from;
- delays in completion of wells, well shut-ins and volatility to operating results caused by multi-well pad drilling, including the effect of such delays on quarterly operating results;
- plans and ability to pursue acquisition opportunities;
- sufficiency of our liquidity position to ensure financial flexibility and fund our operations and capital expenditures;
- estimates of the amount of additional indebtedness we may incur under our revolving credit facility;
- implementation and impact of new accounting pronouncements;
- assumptions regarding share-based compensation;
- settlement of performance share units and restricted share units in cash;
- recognition of compensation expense related to share-based compensation grants;
- expected contributions to our employee benefit plans;
- novation of commodity derivatives upon the closing of the Uinta Basin Divestiture;
- effect of the Strategic Initiatives on employee benefit plans; and
- costs associated with employee retention program and contractual termination benefits, including severance and accelerated vesting of share-based compensations.

Any or all forward-looking statements may turn out to be incorrect. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. These statements are based on current expectations and the current economic environment. They involve a number of risks and uncertainties that are difficult to predict. These statements are not guarantees of future performance. Actual results could differ materially from those expressed or implied in the forward-looking statements. Factors that could cause actual results to differ materially include, but are not limited to the following:

- the risk factors discussed in Item 1A of Part I of the 2017 Form 10-K and Item 1A of Part II of this Quarterly Report on Form 10-Q;
- changes in oil, gas and NGL prices;
- global geopolitical and macroeconomic factors;
- general economic conditions, including the performance of financial markets and interest rates;

- the risks and liabilities associated with acquired assets;
- asset impairments;
- fair value estimates;
- timing of and proceeds from asset divestitures;
- liquidity constraints, including those resulting from the cost and availability of debt and equity financing;
- drilling and completion strategies, methods and results;
- assumptions around well density/spacing and recoverable reserves per well prove to be inaccurate;
- changes in estimated reserve quantities;
- changes in management's assessments as to where QEP's capital can be most profitably deployed;
- shortages and costs of oilfield equipment, services and personnel;
- changes in development plans;
- lack of available pipeline, processing and refining capacity;
- processing volumes and pipeline throughput;
- risks associated with hydraulic fracturing;
- the outcome of contingencies such as legal proceedings;
- delays in obtaining permits and governmental approvals;
- operating risks such as unexpected drilling conditions and risks inherent in the production of oil and gas;
- weather conditions;
- changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning: the environment, climate change, greenhouse gas or other emissions, natural resources, fish and wildlife, hydraulic fracturing, water use and drilling and completion techniques, as well as the risk of legal proceedings arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures;
- derivative activities;
- potential losses or earnings reductions from our commodity price risk management programs;
- volatility in the commodity-futures market;
- failure of internal controls and procedures;
- failure of our information technology infrastructure or applications to prevent a cyberattack;
- elimination of federal income tax deductions for oil and gas exploration and development costs;
- production, severance and property taxation rates;
- tariffs on products we use in our operations on products we sell;
- discount rates;
- regulatory approvals and compliance with contractual obligations;
- actions of, or inaction by federal, state, local or tribal governments, foreign countries and the Organization of Petroleum Exporting Countries;
- lack of, or disruptions in, adequate and reliable transportation for our production;
- competitive conditions;
- production and sales volumes;
- actions of operators on properties in which we own an interest but do not operate;
- estimates of oil and gas reserve quantities;
- reservoir performance;
- operating costs;
- inflation;
- capital costs;
- creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners and other parties;
- volatility in the securities, capital and credit markets;
- actions by credit rating agencies and their impact on the Company;

- changes in guidance issued related to tax reform legislation;
- actions of activist shareholders; and
- other factors, most of which are beyond the Company's control.

QEP undertakes no obligation to publicly correct or update the forward-looking statements in this Quarterly Report on Form 10-Q, in other documents, or on the Company's website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(b) under the Securities Exchange Act of 1934, as amended), as of June 30, 2018. Based on such evaluation, such officers have concluded that, as of June 30, 2018, the Company's disclosure controls and procedures are designed and effective to ensure that information required to be included in the Company's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information required to be disclosed in the Company's reports filed or submitted under the Exchange Act is accumulated and communicated to the Company's management including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating the Company's disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that the Company's controls will succeed in achieving their goals under all potential future conditions.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting (as defined by Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended June 30, 2018, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

There have been no material changes with respect to the legal proceedings reported in our 2017 Form 10-K. Refer to Note 10 – Commitments and Contingencies in Item I of Part I of this Quarterly Report on Form 10-Q for additional information regarding our legal proceedings.

ITEM 1A. RISK FACTORS

Risk factors relating to the Company are set forth in its 2017 Form 10-K. There have been no material changes to such risk factors since filing the 2017 Form 10-K, except for the risk factors below. The risks described below and in the 2017 Form 10 K are not the only risks facing QEP. Additional risks and uncertainties not currently known to QEP or that the Company currently deems to be immaterial also may materially adversely affect its business, financial condition, or future results.

QEP may be unable to successfully execute certain aspects of its announced Strategic Initiatives. QEP announced Strategic Initiatives to transition to a pure-play Permian Basin company. This transition contemplates QEP divesting its assets in the Williston Basin, Uinta Basin and Haynesville Shale. Any divestiture of a business or assets involves

potential risks.

Organizational modifications due to divestitures or other strategic changes can alter the risk and control environments; disrupt ongoing business; distract management and employees; increase expenses; result in additional liabilities, investigations and litigation; harm QEP's strategy; and adversely affect results of operations. Even if these challenges are dealt with successfully, the anticipated benefits of the divestitures may not be realized.

QEP is subject to complex federal, state, tribal, local and other laws and regulations that could adversely affect its cost of doing business and recording of proved reserves. QEP's operations are subject to extensive federal, state, tribal and local tax, energy, environmental, health and safety laws and regulations. The failure to comply with applicable laws and regulations can result in substantial penalties and may threaten the Company's authorization to operate.

Environmental laws and regulations are complex, change frequently and have tended to become more onerous over time. This regulatory burden on the Company's operations increases its cost of doing business and, consequently, affects its profitability. In addition to the costs of compliance, substantial costs may be incurred to take corrective actions at both owned and previously owned facilities. Accidental spills and leaks requiring cleanup may occur in the ordinary course of QEP's business. As standards change, the Company may incur significant costs in cases where past operations followed practices that were considered acceptable at the time, but now require remedial work to meet current standards. Failure to comply with these laws and regulations may result in fines, significant costs for remedial activities, other damages, or injunctions that could limit the scope of QEP's planned operations.

Clean Air Act regulations at 40 C.F.R Part 60, Subpart OOOO (Subpart OOOO) became effective in 2012, with further amendments effective in 2013 and 2014. Subpart OOOO imposes air quality controls and requirements upon QEP's operations. Additionally, in June 2016, the EPA finalized closely related rules in new Subpart OOOOa to achieve additional methane and volatile organic compound reductions from certain activities in the oil and gas industry. The new rules include, among others, new requirements for finding and repairing leaks at new well sites and "reduced emission completion" requirements for hydraulically fractured oil and gas wells. The future status of Subpart OOOOa remains uncertain given ongoing litigation and administrative regulatory actions. EPA has proposed a two-year stay of the effective dates of several requirements of Subpart OOOOa, including fugitive emission requirements, well site pneumatic pump standards, and requirements for certification of closed vent systems. The rules, however, remain in effect as of the filing of this report. The regulatory uncertainty surrounding the implementation of this rule poses some complications for QEP's operations and compliance efforts. Additionally, many states are adopting air permitting and other air quality control regulations specific to oil and gas exploration, production, gathering and processing that are more stringent than existing requirements under federal regulations.

On April 30, 2018, EPA formally designated much of the Uinta Basin as marginal nonattainment under the 2015 ozone standard, effective on August 3, 2018. As a result of this designation, oil and gas operators on the Uinta and Ouray Indian Reservation (U&O Reservation) in the Uinta Basin will not be able to obtain permits by rule for new and modified oil and gas facilities under the federal implementation plan (FIP) established in 2016 for a Federal Minor New Source Review Program in Indian Country. Operators will, instead, be required to obtain individual permits, which may increase the time and expense of obtaining permits on the U&O Reservation. While EPA has recently proposed amendments to apply the FIP to the U&O Reservation portion of the intended Uinta Basin Ozone Nonattainment Area, such amendments may not become effective in time and may not become effective at all, resulting in the unavailability for a period of several months or more of a streamlined permit-by-rule process under the FIP. As a result, our operational costs may increase or our production may be restricted in the Uinta Basin, which could materially and adversely affect our financial condition, results of operations and cash flows.

QEP may be unable to divest of assets on financially attractive terms, resulting in reduced cash proceeds. QEP has announced the sale of certain upstream and midstream assets. QEP's success in divesting assets depends, in part, upon QEP's ability to identify suitable buyers or joint venture partners; assess potential transaction terms; negotiate agreements; and, if applicable, obtain required approvals. Various factors could materially affect QEP's ability to dispose of assets on terms acceptable to QEP. Such factors include, but are not limited to: current and forecasted commodity prices; current laws, regulations and permitting processes impacting oil and gas operations in the areas where the assets are located; covenants under QEP's credit agreement; tax impacts; willingness of the purchaser to assume certain liabilities such as asset retirement obligations; QEP's willingness to indemnify buyers for certain matters; and other factors.

In addition, QEP's credit agreement contains limitations on the amount of asset sales that it is permitted to divest each year. If QEP seeks to sell more assets than is permitted under the credit agreement and is unable to receive waivers of such restrictions, then it may be unable to divest of these assets.

Regulatory requirements to reduce gas flaring and to further restrict emissions could have an adverse effect on our operations. Wells in the Williston Basin of North Dakota and the Permian Basin of Texas, where QEP has significant operations, produce natural gas as well as crude oil. Constraints in third party gas gathering and processing systems in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. In June 2014, the North Dakota Industrial Commission (NDI Commission), North Dakota's chief energy regulator, adopted a policy to reduce the volume of natural gas flared from oil wells in the Williston Basin. The NDI Commission requires operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties may be imposed on certain wells that cannot meet the capture goals. It is possible that other states will require gas capture plans in the future to reduce flaring. Additionally, in November 2016, the Bureau of Land Management (BLM) finalized a new rule related to further controls on the venting, flaring and emissions of natural gas on BLM and tribal leases (the 2016 Venting and Flaring Rule). The rule took effect in January 2017. Some provisions of the rule required compliance in January 2017, including the royalty provisions, while other provisions including those related to further controls on the venting and flaring of natural gas, did not require compliance until January 2018. The 2016 Venting and Flaring Rule is the subject of active litigation in the U.S. District Court for the District of Wyoming. In December 2017, the BLM published a rule to delay the January 2018 compliance deadlines and suspend the obligation to comply with certain provisions that had required compliance in January 2017, until January 2019 (2017 Delay Rule). Certain states and environmental nongovernmental organizations (ENGOs) filed litigation in the U.S. District Court for the Northern District of California challenging the 2017 Delay Rule, and the court preliminarily enjoined the 2017 Delay Rule on February 22, 2018, requiring operators to immediately comply with the 2016 Venting and Flaring Rule. These state and federal gas capture requirements, and any similar future obligations in North Dakota or our other locations, increase our operational costs and may restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows. On April 4, 2018, the U.S. District Court for the District of Wyoming stayed certain compliance obligations required by the 2016 Venting and Flaring while the BLM completes a rulemaking process in which it may revise the 2016 Venting and Flaring Rule. The District of Wyoming's decision has been appealed to the U.S Court of Appeals for the Tenth Circuit.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate. Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various species and wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect threatened and endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species as threatened or endangered in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse effect on our ability to develop and produce our reserves. For example, the Department of the Interior's Fish and Wildlife Service (FWS) listed the Louisiana Pine Snake as threatened under the Endangered Species Act (ESA) in April 2018. The FWS identified Bienville Parish as one of the parishes where the snake can be found. QEP operates within Bienville Parish. Additionally, the FWS plans to issue a proposed rule listing the Lesser Prairie-Chicken as a threatened or endangered species. The Lesser Prairie-Chicken is a grouse species native to Texas, including parts of the Permian Basin where QEP operates. The FWS is in the process of making a final determination in 2018 of whether to list under the ESA.

Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and natural gas that we produce. Climate change, the costs that may be associated with its effects and the regulation of greenhouse gas (GHG) emissions have the potential to affect our business in many ways, including increasing the costs to provide our products, reducing the demand for and consumption of our products (due to changes in both costs and weather patterns) and negatively impacting the economic health of the regions in which we operate, all of which can create financial risks. In addition, if restrictions on GHG emissions significantly increase our costs to produce oil and gas, or significantly decrease demand for our products, the value of our oil and gas reserves may decrease. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. In addition, legislative and regulatory responses related to GHG emissions and climate change may result in increased operating costs, delays in obtaining air emissions and other necessary permits for new or modified facilities and reduced demand for the oil, gas and NGL that QEP produces. Federal and state courts and administrative agencies are considering the scope and scale of climate change regulation under various laws pertaining to the environment, energy use and energy resource development. Federal, state and local governments may also pass laws mandating the use of alternative energy sources, such as wind power and solar energy, or banning the use of gasoline or diesel powered vehicles, which may reduce demand for oil and natural gas. Further, state and local governments may pursue litigation against producers for damages allegedly resulting from climate change. QEP's ability to access and develop new oil and gas reserves may also be restricted by climate change regulation, including GHG reporting and regulation.

Congress has previously considered but not adopted proposed legislation aimed at reducing GHG emissions. The EPA has adopted final regulations under the Clean Air Act for the measurement and reporting of GHG emitted from certain large facilities and, as discussed above, has adopted additional regulations at 40 C.F.R Part 60, Subparts OOOO and OOOOa, to include additional requirements to reduce methane and volatile organic compound emissions from oil and natural gas facilities. The status of Subpart OOOOa is uncertain given the ongoing litigation, administrative reconsideration and proposed action to stay portions of those rules. Additionally, in June 2014, the United States Supreme Court upheld a portion of EPA's GHG stationary source permitting program in Utility Air Regulatory Group v. EPA, but also invalidated a portion of it. The Court's holding does not prevent states from considering and adopting state-only major source permitting requirements based solely on GHG emission levels. Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations to which QEP's operations are subject.

In December 2015, over 190 countries, including the U.S., reached an agreement in Paris (COP 21) to reduce global emissions of GHG (the Paris Agreement). The Paris Agreement provides for the cutting of carbon emissions every five years, beginning in 2023, and sets a goal of keeping global warming to a maximum limit of two degrees Celsius and a target limit of 1.5 degrees Celsius greater than pre-industrial levels. In June 2017, President Trump announced that the U.S. would initiate the formal process to withdraw from the Paris Agreement. Withdrawal will take a few years to implement due to the Paris Agreement's legal structure and language. The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties or domestic regulations. Following the initiation of the U.S. withdrawal from the Paris Agreement, state and local regulation efforts are expected to increase. In several of the states in which QEP operates the regulatory authorities are considering various GHG registration and reduction programs, including methane leak detection monitoring and repair requirements specific to oil and gas facilities. For example, in January 2018, the Utah Department of Environment Quality (UDEQ) adopted additional rules that impose leak detection and repair requirements at certain oil and gas facilities in Utah. In addition, the failure of the federal government to address climate change concerns, including, for example, a protracted delay by President Trump's administration in determining its own carbon-cost estimate (i.e., the estimate of how much carbon pollution costs society via climate damages) after rejecting the $40 per ton of carbon dioxide equivalent estimate of the Obama administration, could empower ENGOs to pursue legal challenges to oil and gas drilling and pipeline projects.

Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in precipitation and extreme weather events. In addition, warmer winters as a result of global warming could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are exacerbated by climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make any estimations of future financial risk to our operations caused by these potential physical risks of climate change unreliable.

QEP relies on highly skilled personnel and, if QEP is unable to retain or motivate key personnel, hire qualified personnel, or transfer knowledge from retiring personnel, QEP's operations may be negatively impacted. QEP's performance largely depends on the talents and efforts of highly skilled individuals. QEP's future success depends on its continuing ability to identify, hire, develop, motivate, and retain highly skilled personnel for all areas of its organization. Competition in the oil and gas industry for qualified employees is intense. QEP's continued ability to compete effectively depends on its ability to attract new employees and to retain and motivate its existing employees. QEP does not maintain key-man insurance for its key management personnel. In connection with the announcement of its plans to divest of its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley, QEP entered into retention and severance agreements with its executives and other key management personnel. Nonetheless, the loss of services of one or more of its key management personnel could have a negative impact on QEP's financial condition and results of operations.

General economic and other conditions could negatively impact QEP's operating results. QEP's operating results may also be negatively affected by changes in global economic conditions; availability and economic viability of oil and gas properties for sale or exploration; rate of inflation and interest rates; weather and natural disasters; changes in customers' credit ratings; competition from other forms of energy and other pipeline and storage facilities; effects of accounting policies issued periodically by accounting standard-setting bodies; tariffs on steel and steel products used in oil and gas operations; tariffs on oil, gas and NGLs: and terrorist attacks or acts of war.

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

On February 28, 2018, QEP announced the authorization by its Board of Directors to repurchase up to $1.25 billion of the Company's outstanding shares of common stock (the February 2018 $1.25 billion Repurchase Program). The timing and amount of any QEP share repurchases will be subject to available liquidity, market conditions and proceeds from the asset sales. The share repurchase program does not obligate QEP to acquire any specific number of shares and may be discontinued at any time.

The following repurchases of QEP shares were made by QEP in association with vested restricted share awards withheld for
taxes and pursuant to the Company's share repurchase authorization.

Period	Total shares purchased[1][2]	Weighted-average price paid per share	Total shares purchased as part of publicly announced plans or programs	Remaining dollar amount that may be purchased under the plans or programs (in millions)
April 1, 2018 - April 30, 2018	651,838	$ 9.64	592,310	$ 1,191.6
May 1, 2018 - May 31, 2018	35,214	$ 12.20	—	$ 1,191.6
June 1, 2018 - June 30, 2018	7,812	$ 12.06	—	$ 1,191.6
Total	694,864		592,310	

(1) During the three months ended June 30, 2018, QEP purchased 102,554 shares from employees in connection with the settlement of income tax and related benefit withholding obligations arising from the vesting of restricted share grants.

(2) During the three months ended June 30, 2018, QEP repurchased and retired 592,310 shares under the February 2018 $1.25 billion Repurchase Program at a weighted average price of $9.37 per share, excluding commission of $0.02 per share, for $5.6 million. Shares are as of the settlement date.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

The following exhibits are being filed as part of this report:

Exhibit No.	Exhibits
3.1	Amended and Restated Certificate of Incorporation dated May 15, 2018 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on May 17, 2018).
3.2	Amended and Restated Bylaws, dated effective October 23, 2017 (incorporated by reference to Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on October 25, 2017).
10.1+	2018 Long-Term Incentive Plan, as adopted on May 15, 2018 (incorporated by reference to the Company’s Current Report on Form 8-K, filed with the Securities and Exchange Commission on May 17, 2018).
10.2*+	Form of Restricted Stock Agreement for restricted stock granted to executive officers after May 2018 under the 2018 Long-Term Incentive Plan.
10.3*+	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers after May 2018 under the 2012 Cash Incentive Plan.
10.4*+	Form of Deferred Share Award Agreement for shares of common stock granted to executives under the 2019 Long-Term Incentive Plan and for deferral of receipt of such shares in accordance with the terms of the Deferred Compensation Wrap Plan - Deferred Compensation Program.
31.1	Certification signed by Charles B. Stanley, QEP Resources, Inc.'s Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification signed by Richard J. Doleshek, QEP Resources, Inc.'s Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification signed by Charles B. Stanley and Richard J. Doleshek, QEP Resources, Inc.'s Chief Executive Officer and Chief Financial Officer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document
101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document

+ Indicates a management contract or compensatory plan or arrangement.

* Filed herewith

** These interactive data files are furnished and deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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.

QEP RESOURCES, INC.
(Registrant)

July 25, 2018 /s/ Charles B. Stanley
Charles B. Stanley,
Chairman, President and Chief Executive Officer

July 25, 2018 /s/ Richard J. Doleshek
Richard J. Doleshek,
Executive Vice President and Chief Financial Officer