

SM Energy Co  
Form 10-Q  
May 04, 2018

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UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
WASHINGTON, D.C. 20549  
FORM 10-Q

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

For the quarterly period ended March 31, 2018

OR

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission File Number 001-31539

SM ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware 41-0518430

(State or other jurisdiction (I.R.S. Employer of incorporation or organization) Identification No.)

1775 Sherman Street, Suite 1200, Denver, Colorado 80203  
(Address of principal executive offices) (Zip Code)

(303) 861-8140

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (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  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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  No

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  Accelerated filer

Non-accelerated filer  Smaller reporting company   
(Do not check if a smaller reporting company)

Emerging growth company

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

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or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

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

As of April 25, 2018, the registrant had 111,687,016 shares of common stock, \$0.01 par value, outstanding.

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## PART I. FINANCIAL INFORMATION

## ITEM 1. FINANCIAL STATEMENTS

## SM ENERGY COMPANY AND SUBSIDIARIES

## CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(in thousands, except share data)

	March 31, 2018	December 31, 2017
<b>ASSETS</b>		
Current assets:		
Cash and cash equivalents	\$643,337	\$ 313,943
Accounts receivable	192,562	160,154
Derivative assets	77,296	64,266
Prepaid expenses and other	9,997	10,752
Total current assets	923,192	549,115
Property and equipment (successful efforts method):		
Proved oil and gas properties	5,824,014	6,139,379
Accumulated depletion, depreciation, and amortization	(2,893,674 )	(3,171,575 )
Unproved oil and gas properties	1,986,070	2,047,203
Wells in progress	405,549	321,347
Oil and gas properties held for sale, net	234,618	111,700
Other property and equipment, net of accumulated depreciation of \$52,483 and \$49,985, respectively	112,972	106,738
Total property and equipment, net	5,669,549	5,554,792
Noncurrent assets:		
Derivative assets	35,128	40,362
Other noncurrent assets	32,119	32,507
Total noncurrent assets	67,247	72,869
Total assets	\$6,659,988	\$ 6,176,776
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
Current liabilities:		
Accounts payable and accrued expenses	\$468,108	\$ 386,630
Derivative liabilities	181,068	172,582
Total current liabilities	649,176	559,212
Noncurrent liabilities:		
Revolving credit facility	—	—
Senior Notes, net of unamortized deferred financing costs	2,770,979	2,769,663
Senior Convertible Notes, net of unamortized discount and deferred financing costs	141,269	139,107
Asset retirement obligations	85,407	103,026
Asset retirement obligations associated with oil and gas properties held for sale	23,139	11,369
Deferred income taxes	178,423	79,989
Derivative liabilities	53,712	71,402
Other noncurrent liabilities	45,786	48,400
Total noncurrent liabilities	3,298,715	3,222,956
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, \$0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 111,687,016 and 111,687,016 shares, respectively	1,117	1,117
Additional paid-in capital	1,747,035	1,741,623

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Retained earnings <sup>(1)</sup>	980,444	665,657
Accumulated other comprehensive loss <sup>(1)</sup>	(16,499 )	(13,789 )
Total stockholders' equity	2,712,097	2,394,608
Total liabilities and stockholders' equity	\$6,659,988	\$ 6,176,776

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<sup>(1)</sup> The Company reclassified \$3.0 million of tax effects stranded in accumulated other comprehensive loss to retained earnings as of January 1, 2018. Please refer to Note 1 - Summary of Significant Accounting Policies for further detail. The accompanying notes are an integral part of these condensed consolidated financial statements.

SM ENERGY COMPANY AND SUBSIDIARIES  
 CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

(in thousands, except per share data)

	For the Three Months Ended March 31,	
	2018	2017 (as adjusted)
Operating revenues and other income:		
Oil, gas, and NGL production revenue	\$382,886	\$333,198
Net gain on divestiture activity	385,369	37,463
Other operating revenues	1,340	2,077
Total operating revenues and other income	769,595	372,738
Operating expenses:		
Oil, gas, and NGL production expense	120,879	138,046
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	130,473	137,812
Exploration	13,727	11,817
Abandonment and impairment of unproved properties	5,625	—
General and administrative	27,682	28,817
Net derivative (gain) loss	7,529	(114,774 )
Other operating expenses	4,612	4,859
Total operating expenses	310,527	206,577
Income from operations	459,068	166,161
Interest expense	(43,085 )	(46,953 )
Loss on extinguishment of debt	—	(35 )
Other non-operating income (expense), net	409	(233 )
Income before income taxes	416,392	118,940
Income tax expense	(98,991 )	(44,506 )
Net income	\$317,401	\$74,434
Basic weighted-average common shares outstanding	111,696	111,258
Diluted weighted-average common shares outstanding	112,879	111,329
Basic net income per common share	\$2.84	\$0.67
Diluted net income per common share	\$2.81	\$0.67
Dividends per common share	\$0.05	\$0.05

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

SM ENERGY COMPANY AND SUBSIDIARIES  
 CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (UNAUDITED)  
 (in thousands)

	For the Three Months Ended March 31,	
	2018	2017
Net income	\$317,401	\$74,434
Other comprehensive income (loss), net of tax:		
Pension liability adjustment	260	(567 )
Total other comprehensive income (loss), net of tax	260	(567 )
Total comprehensive income	\$317,661	\$73,867

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

SM ENERGY COMPANY AND SUBSIDIARIES  
 CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)  
 (in thousands)

	For the Three Months Ended March 31,	
	2018	2017 (as adjusted)
Cash flows from operating activities:		
Net income	\$317,401	\$74,434
Adjustments to reconcile net income to net cash provided by operating activities:		
Net gain on divestiture activity	(385,369 )	(37,463 )
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	130,473	137,812
Abandonment and impairment of unproved properties	5,625	—
Stock-based compensation expense	5,412	5,455
Net derivative (gain) loss	7,529	(114,774 )
Derivative settlement gain (loss)	(24,528 )	7
Amortization of debt discount and deferred financing costs	3,866	4,946
Loss on extinguishment of debt	—	35
Deferred income taxes	98,366	33,225
Other, net	(2,527 )	3,376
Changes in current assets and liabilities:		
Accounts receivable	(4,464 )	30,407
Prepaid expenses and other	755	178
Accounts payable and accrued expenses	(8,825 )	(5,497 )
Accrued derivative settlements	(3,579 )	2,838
Net cash provided by operating activities	140,135	134,979
Cash flows from investing activities:		
Net proceeds from the sale of oil and gas properties	490,780	744,333
Capital expenditures	(301,521 )	(154,401 )
Acquisition of proved and unproved oil and gas properties	—	(75,105 )
Net cash provided by investing activities	189,259	514,827
Cash flows from financing activities:		
Proceeds from credit facility	—	397,500
Repayment of credit facility	—	(397,500 )
Cash paid to repurchase Senior Notes	—	(2,344 )
Cash paid for extinguishment of debt	—	(13 )
Other, net	—	(160 )
Net cash used in financing activities	—	(2,517 )
Net change in cash, cash equivalents, and restricted cash <sup>(1)</sup>	329,394	647,289
Cash, cash equivalents, and restricted cash at beginning of period <sup>(1)</sup>	313,943	12,372
Cash, cash equivalents, and restricted cash at end of period <sup>(1)</sup>	\$643,337	\$659,661

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



SM ENERGY COMPANY AND SUBSIDIARIES  
 CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED) (Continued)  
 (in thousands)

Supplemental schedule of additional cash flow information and non-cash activities:

	For the Three Months Ended March 31,	
	2018	2017 (as adjusted)
Operating activities:		
Cash paid for interest, net of capitalized interest	\$(40,060)	\$(42,872)
Net cash (paid) refunded for income taxes	\$(106 )	\$15
Investing activities:		
Changes in capital expenditure accruals and other	\$60,299	\$27,214
Supplemental non-cash investing activities:		
Carrying value of properties exchanged	\$—	\$24,544
Supplemental non-cash financing activities:		
Non-cash loss on extinguishment of debt, net	\$—	\$22
Dividends declared, but not paid	\$5,584	\$5,563

Refer to Note 1 - Summary of Significant Accounting Policies for a reconciliation of cash, cash equivalents, and  
 (1) restricted cash reported to the amounts reported within the accompanying condensed consolidated balance sheets  
 (“accompanying balance sheets”).

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

SM ENERGY COMPANY AND SUBSIDIARIES  
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS  
(UNAUDITED)

Note 1 - Summary of Significant Accounting Policies

Description of Operations

SM Energy Company, together with its consolidated subsidiaries (“SM Energy” or the “Company”), is an independent energy company engaged in the acquisition, exploration, development, and production of crude oil and condensate, natural gas, and natural gas liquids (also respectively referred to as “oil,” “gas,” and “NGLs” throughout this report) in onshore North America.

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements include the accounts of SM Energy and have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”) for interim financial information, the instructions to Quarterly Report on Form 10-Q, and Regulation S-X. These financial statements do not include all information and notes required by GAAP for annual financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in SM Energy’s Annual Report on Form 10-K for the year ended December 31, 2017 (the “2017 Form 10-K”). In the opinion of management, all adjustments, consisting of normal recurring adjustments considered necessary for a fair presentation of interim financial information, have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year. In connection with the preparation of the Company’s unaudited condensed consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of March 31, 2018, and through the filing of this report. Certain prior period amounts have been reclassified to conform to the current presentation on the accompanying condensed consolidated financial statements.

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 1 - Summary of Significant Accounting Policies to the Company’s 2017 Form 10-K, and are supplemented by the notes to the unaudited condensed consolidated financial statements included in this report. These unaudited condensed consolidated financial statements should be read in conjunction with the Company’s 2017 Form 10-K.

Recently Issued Accounting Standards

Effective December 31, 2017, the Company early adopted, on a retrospective basis, Financial Accounting Standards Board (“FASB”) Accounting Standards Update (“ASU”) No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (“ASU 2016-15”) and FASB ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (“ASU 2016-18”). ASU 2016-15 is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows and ASU 2016-18 is intended to clarify guidance on the classification and presentation of restricted cash and restricted cash equivalents in the statement of cash flows. Please refer to Note 1 - Summary of Significant Accounting Policies in the Company’s 2017 Form 10-K for more information.

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The accompanying condensed consolidated statements of cash flows (“accompanying statements of cash flows”) line items that were adjusted as a result of the adoption of ASU 2016-15 and ASU 2016-18 for the three months ended March 31, 2017, are summarized as follows:

	For the Three Months Ended March 31, 2017	
	As Reported	As Adjusted
	(in thousands)	
Cash flows from operating activities:		
Non-cash loss on extinguishment of debt, net	\$22	N/A
Loss on extinguishment of debt	N/A	\$35
Net cash provided by operating activities	\$134,966	\$134,979
Cash flows from investing activities:		
Other, net	\$2,486	N/A
Net cash provided by investing activities	\$517,313	\$514,827
Cash flows from financing activities:		
Cash paid for extinguishment of debt	N/A	\$(13 )
Net cash used in financing activities	\$(2,504 )	\$(2,517 )
Net change in cash and cash equivalents	\$649,775	N/A
Net change in cash, cash equivalents, and restricted cash	N/A	\$647,289
Cash and cash equivalents at beginning of period	\$9,372	N/A
Cash, cash equivalents, and restricted cash at beginning of period	N/A	\$12,372
Cash and cash equivalents at end of period	\$659,147	N/A
Cash, cash equivalents, and restricted cash at end of period	N/A	\$659,661

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the accompanying balance sheets:

	As of March 31, 2018	As of December 31, 2017
	(in thousands)	
Cash and cash equivalents	\$643,337	\$313,943
Restricted cash	—	—
Total cash, cash equivalents, and restricted cash	\$643,337	\$313,943

Effective January 1, 2018, the Company adopted FASB ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) and all related ASUs (“ASU 2014-09”). Under the new guidance, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The Company adopted ASU 2014-09 using the modified retrospective transition method, which was applied to all active contracts as of the effective date. The adoption of ASU 2014-09 did not result in a change to current or prior period results nor did it result in a material change to the Company’s business processes, systems, or controls. However, upon adopting ASU 2014-09, the Company expanded its disclosures to comply with the expanded disclosure requirements of ASU 2014-09. Please refer to Note 2 - Revenue from Contracts with Customers for additional discussion.

Effective January 1, 2018, the Company adopted FASB ASU No. 2017-07, Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (“ASU 2017-07”). ASU 2017-07 requires presentation of service cost in the same line item(s) as other compensation costs arising from services rendered by employees during the period and presentation of the remaining components of net

benefit cost in a separate line item, outside of operating items, which the Company adopted with retrospective application. In addition, only the service

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component of the net benefit cost is eligible for capitalization, which the Company adopted with prospective application. Please refer to Note 1 - Summary of Significant Accounting Policies in the Company's 2017 Form 10-K for more information.

The March 31, 2017, accompanying condensed consolidated statements of operations ("accompanying statements of operations") line items that were adjusted as a result of the adoption of ASU 2017-07 are summarized as follows:

	For the Three Months Ended March 31, 2017	
	As Reported	As Adjusted
	(in thousands)	
Operating expenses:		
Exploration	\$11,978	\$11,817
General and administrative	\$29,224	\$28,817
Total operating expenses	\$207,145	\$206,577
Income from operations	\$165,593	\$166,161

Other non-operating income (expense), net \$335      \$(233    )

Effective January 1, 2018, the Company early adopted ASU No. 2018-02, Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income ("ASU 2018-02") by applying the changes in the period of adoption. ASU 2018-02 permits entities to reclassify tax effects stranded in accumulated other comprehensive income (loss) to retained earnings as a result of the enactment into law on December 22, 2017 of H.R.1, formally the Tax Cuts and Jobs Act (the "2017 Tax Act"). As a result of adopting ASU 2018-02, the Company reclassified \$3.0 million of tax effects stranded in accumulated other comprehensive loss to retained earnings as of January 1, 2018. The Company's policy for releasing income tax effects within accumulated other comprehensive loss is an incremental, unit-of-account approach.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which requires recognition of right-of-use assets and lease payment liabilities on the balance sheet by lessees for virtually all leases currently classified as operating leases. The Company has established a cross-functional project team and is leveraging external consultants to evaluate the impacts of ASU 2016-02 and other related guidance, which includes an analysis of non-cancelable leases, drilling rig contracts, certain midstream agreements, and other existing arrangements. Further, the Company is also evaluating policies, controls, and processes that will be necessary to support the additional accounting and disclosure requirements. The Company will adopt ASU 2016-02 and other related guidance on January 1, 2019, using the modified retrospective approach. Adoption of this guidance is expected to result in an increase in right-of-use assets and related liabilities on the Company's consolidated balance sheets, however, the full impact to the Company's financial statements and related disclosures is still being evaluated.

Other than as disclosed above or in the Company's 2017 Form 10-K, there are no other ASUs applicable to the Company that would have a material effect on the Company's consolidated financial statements and related disclosures that have been issued but not yet adopted by the Company as of March 31, 2018, and through the filing of this report.

#### Note 2 - Revenue from Contracts with Customers

The Company recognizes its share of revenue from the sale of produced oil, gas, and NGLs in its Permian, South Texas & Gulf Coast, and Rocky Mountain regions. During the three months ended March 31, 2018, the Company entered into two definitive agreements to sell substantially all of its producing properties and related assets in its Rocky Mountain region. One transaction closed in the first quarter of 2018 and the second transaction is expected to close in the second quarter of 2018. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions for additional detail. Oil, gas, and NGL production revenue presented within the accompanying statements of operations is reflective of the revenue generated from contracts with customers.



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The following tables present the disaggregation of oil, gas, and NGL production revenue by product type for each of the Company's operating regions:

	For the Three Months Ended March 31, 2018			
	Permian	South Texas & Gulf Coast	Rocky Mountain	Total
	(in thousands)			
Oil, gas, and NGL production revenue:				
Oil production revenue	\$205,794	\$19,583	\$35,683	\$261,060
Gas production revenue	24,876	52,733	1,500	79,109
NGL production revenue	124	41,770	823	42,717
Total oil, gas, and NGL production revenue	\$230,794	\$114,086	\$38,006	\$382,886
Relative percentage	60	% 30	% 10	% 100 %

	For the Three Months Ended March 31, 2017			
	Permian	South Texas & Gulf Coast	Rocky Mountain	Total
	(in thousands)			
Oil, gas, and NGL production revenue:				
Oil production revenue	\$81,499	\$38,864	\$47,261	\$167,624
Gas production revenue	11,309	88,201	1,641	101,151
NGL production revenue	147	63,357	919	64,423
Total oil, gas, and NGL production revenue	\$92,955	\$190,422	\$49,821	\$333,198
Relative percentage	28	% 57	% 15	% 100 %

The Company recognizes oil, gas, and NGL production revenue at the point in time when control of the product transfers to the customer, which differs depending on the contractual terms of each of the Company's arrangements. Transfer of control drives the presentation of transportation, gathering, processing, and other post-production expenses ("fees and other deductions") within the accompanying statements of operations. Fees and other deductions incurred prior to control transfer are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations, while fees and other deductions incurred subsequent to control transfer are recorded as a reduction of oil, gas, and NGL production revenue. The Company has four general categories under which oil, gas, and NGL production revenue is generated. Each of the Company's operating regions generate production revenue from a combination of some or all of the four different contract types summarized below:

- 1) The Company sells oil production at or near the wellhead and receives an agreed-upon index price from the purchaser, net of basis, quality, and transportation differentials. Under this arrangement, control transfers at or near the wellhead.
- 2) The Company sells unprocessed gas to a midstream processor at the wellhead or inlet of the midstream processing facility. The midstream processor gathers and processes the raw gas stream and remits proceeds to the Company from the ultimate sale of the processed NGLs and residue gas to third parties. In such arrangements, the midstream processor obtains control of the product at the wellhead or inlet and is considered the customer. Proceeds received for unprocessed gas under these arrangements are reflected as gas production revenue in the table above and are recorded net of transportation and processing fees incurred by the midstream processor after control has transferred.
- 3) The Company has certain processing arrangements that include the delivery of unprocessed gas to the inlet of a midstream processor's facility for processing. Upon completion of processing, the midstream processor purchases the NGLs and redelivers residue gas back to the Company in-kind. For the NGLs extracted during processing, the midstream processor remits payment to the Company based on the proceeds it generates from selling the NGLs to other third parties. For the residue gas taken in-kind, the Company has separate sales contracts where control transfers at points downstream of the processing facility. Given the structure of these arrangements and where control transfers, the Company separately recognizes gathering, transportation, and processing fees incurred prior to control transfer. These fees are recorded within the oil, gas, and NGL production expense line item on the

accompanying statements of operations.

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The Company has certain midstream processing arrangements where unprocessed gas is delivered to the inlet of the midstream processor's facility for processing. Upon completion of processing, the midstream processor purchases the processed NGLs and residue gas and remits the proceeds to the Company from the sale of the products to 4) third-party customers. In these arrangements, control transfers at the tailgate of the midstream processing facility for both products. Given the structure of these arrangements and where control transfers, the Company separately recognizes gathering, transportation, and processing fees incurred prior to control transfer. These fees are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations.

Significant judgments made in applying the guidance in ASC Topic 606, Revenue from Contracts with Customers ("ASC 606") relate to the point in time when control transfers to customers in gas processing arrangements with midstream processors. The Company does not believe that significant judgments are required with respect to the determination of the transaction price, including amounts that represent variable consideration, as volume and price carry a low level of estimation uncertainty given the precision of volumetric measurements and the use of index pricing with predictable differentials. Accordingly, the Company does not consider estimates of variable consideration to be constrained.

The Company's contractual performance obligations arise upon the production of hydrocarbons from wells the Company has an ownership interest in. The performance obligations are considered satisfied upon control transferring to a customer at the wellhead, inlet, or tailgate of the midstream processor's processing facility, or other contractually specified delivery point. The time period between production and satisfaction of performance obligations is generally less than one day; thus, there are no material unsatisfied or partially unsatisfied performance obligations at the end of the reporting period.

Revenue is recorded in the month when contractual performance obligations are satisfied. However, settlement statements from the purchasers of hydrocarbons and the related cash consideration are generally received 30 to 90 days after production has occurred. As a result, the Company must estimate the amount of production delivered to the customer and the consideration that will ultimately be received for sale of the product. Estimated revenue due to the Company is recorded within accounts receivable on the accompanying balance sheets until payment is received. The accounts receivable balances from contracts with customers within the accompanying balance sheets as of March 31, 2018, and December 31, 2017, were \$97.1 million and \$96.6 million, respectively. As of March 31, 2018, only an immaterial balance remained related to accounts receivable from customers that were outstanding as of December 31, 2017. To estimate accounts receivable from contracts with customers, the Company uses knowledge of its properties, historical performance, contractual arrangements, NYMEX, OPIS and local spot market prices, quality and transportation differentials, and other factors as the basis for these estimates. Differences between estimates and actual amounts received for product sales are recorded in the month that payment is received from the purchaser. Revenue recognized for the three months ended March 31, 2018, that related to performance obligations satisfied in prior reporting periods was immaterial.

#### Note 3 - Divestitures, Assets Held for Sale, and Acquisitions

##### Divestitures

On March 26, 2018, the Company divested approximately 112,000 net acres of its Powder River Basin assets (the "PRB Divestiture"), for total cash received at closing, net of costs (referred to throughout this report as "net divestiture proceeds"), of \$490.8 million, subject to final purchase price adjustments, and recorded an estimated net gain of \$409.2 million for the three months ended March 31, 2018. These assets were classified as held for sale as of December 31, 2017.

On March 10, 2017, the Company closed the divestiture of its outside-operated Eagle Ford shale assets, including ownership interest in related midstream assets, for net divestiture proceeds received at closing, of \$747.4 million and net divestiture proceeds of \$744.1 million after final purchase price adjustments. The Company recorded a net estimated gain of \$398.1 million for the three months ended March 31, 2017, and a final net gain of \$396.8 million related to these divested assets for the year ended December 31, 2017.

### Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and it is probable the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less estimated costs to sell. When assets no longer meet the criteria of assets held for sale, they are measured at the lower of the carrying value of the assets before being classified as held for sale, adjusted for any depletion, depreciation, and amortization expense that would have been recognized, or the fair value at the date they are reclassified to assets held for use. Any gain or loss recognized on assets held for sale or on assets held for sale that are subsequently reclassified to assets held for use is reflected in the net gain on divestiture activity line item in the accompanying statements of operations.

As of March 31, 2018, the accompanying balance sheets present \$234.6 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense, which consist of the Company's remaining assets in the Williston Basin located in Divide County, North Dakota ("Divide County"), and the Company's third-party operated assets, known as Halff East, located in Upton County, Texas. A corresponding asset retirement obligation liability of \$23.1 million is separately presented for these assets held for sale. Certain assets held for sale were written down by \$24.1 million to reflect fair value less estimated costs to sell upon classification as held for sale during the three months ended March 31, 2018.

The Company has entered into definitive agreements for the sale of its Divide County assets (the "Divide County Divestiture") and its Halff East assets in the Midland Basin (the "Halff East Divestiture") for a total gross purchase price of \$292.3 million, subject to certain price adjustments. The Company expects both of these divestitures to close during the second quarter of 2018. These closings are subject to the satisfaction of customary closing conditions, and there can be no assurance that either transaction will close on time or at all.

The following table presents loss before income taxes for the three months ended March 31, 2018, and 2017, for the Company's Divide County assets held for sale as of March 31, 2018, which are considered a significant asset group.

	For the Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Loss before income taxes <sup>(1)</sup>	\$(11,497)	\$(332,719)

Loss before income taxes reflects oil, gas, and NGL production revenue, less oil, gas, and NGL production <sup>(1)</sup> expense, depletion, depreciation, amortization, and asset retirement obligation liability accretion expense, and impairment expense.

As of March 31, 2017, the Company had certain assets in its Rocky Mountain region classified as held for sale. These assets were written down by \$359.6 million to reflect fair value less estimated costs to sell upon classification as held for sale during the three months ended March 31, 2017.

### Acquisitions

Subsequent to March 31, 2018, the Company acquired approximately 760 net acres of unproved properties in Martin County, Texas, for \$24.6 million. Under authoritative accounting guidance, this transaction was considered an asset acquisition. Therefore, the properties will be recorded based on the fair value of the total consideration transferred on the acquisition date and the transaction costs will be capitalized as a component of the cost of the assets acquired.

## Note 4 - Income Taxes

The income tax expense recorded for the three months ended March 31, 2018, and 2017, differs from the amounts that would be provided by applying the statutory United States federal income tax rate to income or loss before income taxes primarily due to the effect of state income taxes, excess tax benefits and deficiencies from share-based payment awards, changes in valuation allowances, and accumulated impacts of other smaller permanent differences. The quarterly rate can also be affected by the proportional impacts of forecasted net income or loss as of each period end presented.

The provision for income taxes for the three months ended March 31, 2018, and 2017, consisted of the following:

	For the Three Months	
	Ended	
	March 31,	
	2018	2017
	(in thousands)	
Current portion of income tax expense:		
Federal	\$—	\$(7,439 )
State	(625 )	(3,842 )
Deferred portion of income tax expense	(98,366 )	(33,225 )
Income tax expense	\$(98,991)	\$(44,506)
Effective tax rate	23.8 %	37.4 %

The enactment of the 2017 Tax Act on December 22, 2017, reduced the Company's federal tax rate for 2018 and future years from 35 percent to 21 percent. Although the Company believes it has properly analyzed the tax accounting impacts of the 2017 Tax Act, it will continue to monitor provisions with discrete rate impacts, such as the limitation on executive compensation for subsequent events and guidance within the one year measurement period. There are no new estimates or finalized income tax items associated with the 2017 Tax Act included in income tax expense for the three months ended March 31, 2018.

On a year-to-date basis, a change in the Company's effective tax rate between reporting periods will generally reflect differences in its estimated highest marginal state tax rate due to changes in the composition of income or loss from Company activities among multiple state tax jurisdictions. Cumulative effects of state tax rate changes are reflected in the period legislation is enacted. However, state rate differences between reported periods were not significant. Excess tax benefits and deficiencies from share-based payment awards impact the Company's effective tax rate between periods.

In 2017, the Company re-evaluated various factors affecting deferred tax assets related to net operating losses and tax credits, and determined utilization would be appropriate. The change in the current portion of income tax expense between periods reflects the effect of this determination. The Company is generally no longer subject to United States federal or state income tax examinations by tax authorities for years before 2013.

## Note 5 - Long-Term Debt

## Credit Agreement

The Company's Fifth Amended and Restated Credit Agreement, as amended, (the "Credit Agreement") provides for a maximum loan amount of \$2.5 billion and has a maturity date of December 10, 2019. As of March 31, 2018, the Company's borrowing base and aggregate lender commitments were \$925 million, which were unchanged from December 31, 2017. Subsequent to March 31, 2018, as part of the regular, semi-annual borrowing base redetermination process, the borrowing base and aggregate lender commitments were increased to \$1.4 billion and \$1.0 billion, respectively. The increase in the borrowing base was primarily driven by the increased value of the Company's estimated proved reserves at December 31, 2017. The next scheduled redetermination date is October 1, 2018.

The Company must comply with certain financial and non-financial covenants under the terms of the Credit Agreement and was in compliance with all such covenants as of March 31, 2018, and through the filing of this report. Interest and commitment fees are accrued based on a borrowing base utilization grid set forth in the Credit Agreement as presented in Note 5 - Long-Term Debt in the Company's 2017 Form 10-K. Eurodollar loans accrue interest at the London Interbank Offered Rate, plus the applicable margin from the utilization grid, and Alternate Base Rate and

swingline loans accrue interest at the prime rate, plus the applicable margin from the utilization grid. Commitment fees are accrued on the

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unused portion of the aggregate lender commitment amount at rates from the utilization grid and are included in interest expense in the accompanying statements of operations.

The following table presents the outstanding balance, total amount of letters of credit outstanding, and available borrowing capacity under the Credit Agreement as of April 25, 2018, March 31, 2018, and December 31, 2017:

	As of April 25, 2018	As of March 31, 2018	As of December 31, 2017
	(in thousands)		
Credit facility balance <sup>(1)</sup>	\$—	\$—	\$—
Letters of credit <sup>(2)</sup>	200	200	200
Available borrowing capacity	999,800	924,800	924,800
Total aggregate lender commitment amount	\$1,000,000	\$925,000	\$925,000

Unamortized deferred financing costs attributable to the credit facility are presented as a component of other

<sup>(1)</sup> noncurrent assets on the accompanying balance sheets and totaled \$2.7 million and \$3.1 million as of March 31, 2018, and December 31, 2017, respectively.

<sup>(2)</sup> Letters of credit outstanding reduce the amount available under the credit facility on a dollar-for-dollar basis.

#### Senior Notes

The Company's Senior Notes consist of 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, 6.50% Senior Notes due 2023, 5.0% Senior Notes due 2024, 5.625% Senior Notes due 2025, and 6.75% Senior Notes due 2026 (collectively referred to as "Senior Notes"). The Senior Notes, net of unamortized deferred financing costs line on the accompanying balance sheets as of March 31, 2018, and December 31, 2017, consisted of the following:

	As of March 31, 2018			As of December 31, 2017		
	Principal Amount	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs	Principal Amount	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs
	(in thousands)					
6.50% Senior Notes due 2021	\$344,611	\$ 2,483	\$ 342,128	\$344,611	\$ 2,656	\$ 341,955
6.125% Senior Notes due 2022	561,796	5,505	556,291	561,796	5,800	555,996
6.50% Senior Notes due 2023	394,985	3,525	391,460	394,985	3,707	391,278
5.0% Senior Notes due 2024	500,000	5,380	494,620	500,000	5,610	494,390
5.625% Senior Notes due 2025	500,000	6,487	493,513	500,000	6,714	493,286
6.75% Senior Notes due 2026	500,000	7,033	492,967	500,000	7,242	492,758
Total	\$2,801,392	\$ 30,413	\$ 2,770,979	\$2,801,392	\$ 31,729	\$ 2,769,663

The Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt, and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the Senior Notes. The Company is subject to certain covenants under the indentures governing the Senior Notes and was in compliance with all such covenants as of March 31, 2018, and through the filing of this report. The Company may redeem some or all of its Senior Notes prior to their maturity at redemption prices based on a premium, plus accrued and unpaid interest as described in the indentures governing the Senior Notes.

### Senior Convertible Notes

The Company's Senior Convertible Notes consist of \$172.5 million in aggregate principal amount of 1.50% Senior Convertible Notes due July 1, 2021 (the "Senior Convertible Notes"). The Senior Convertible Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt, and are senior in right of payment to any future subordinated debt. Please refer to Note 5 - Long-Term Debt in the Company's 2017 Form 10-K for additional detail on the Company's Senior Convertible Notes and associated capped call transactions.

The Senior Convertible Notes were not convertible at the option of holders as of March 31, 2018, or through the filing of this report. Notwithstanding the inability to convert, the if-converted value of the Senior Convertible Notes as of March 31, 2018, did not exceed the principal amount. The debt discount and debt-related issuance costs are amortized to the principal value of the Senior Convertible Notes as interest expense through the maturity date of July 1, 2021. Interest expense recognized on the Senior Convertible Notes related to the stated interest rate and amortization of the debt discount totaled \$2.6 million and \$2.4 million for the three months ended March 31, 2018, and 2017, respectively.

There have been no changes to the initial net carrying amount of the equity component of the Senior Convertible Notes recorded in additional paid-in capital on the accompanying balance sheets. The net carrying amount of the liability component of the Senior Convertible Notes, as reflected on the accompanying balance sheets as of March 31, 2018, and December 31, 2017, consisted of the following:

	As of March 31, 2018	As of December 31, 2017
	(in thousands)	
Principal amount of Senior Convertible Notes	\$172,500	\$172,500
Unamortized debt discount	(28,251 )	(30,183 )
Unamortized deferred financing costs	(2,980 )	(3,210 )
Net carrying amount	\$141,269	\$139,107

The Company is subject to certain covenants under the indenture governing the Senior Convertible Notes and was in compliance with all such covenants as of March 31, 2018, and through the filing of this report.

### Note 6 - Commitments and Contingencies

#### Commitments

As of March 31, 2018, the Company had total gathering, processing, transportation throughput, and purchase commitments with various third parties that require delivery of a minimum quantity of 18 MMBbl of oil, 769 Bcf of gas, and 23 MMBbl of produced water through 2028 and a minimum purchase quantity of 10 MMBbl of water by 2022. If the Company fails to deliver or purchase any product, as applicable, the aggregate undiscounted future deficiency payments as of March 31, 2018, would total approximately \$461.5 million. As of the filing of this report, the Company does not expect to incur any material shortfalls with regard to these commitments.

The Company entered into new and amended drilling rig and completion contracts during the first three months of 2018 and subsequent to March 31, 2018. As of the filing of this report, the Company's drilling rig and completion contract commitments totaled \$158.3 million; however, if the Company terminated these contracts immediately, it would incur penalties of \$40.6 million.

Additionally, as of March 31, 2018, the Company had fixed price contracts with various third parties to purchase electricity through 2027 for a total of \$31.7 million. As of the filing of this report, the Company expects to meet these purchase commitments.

There were no other material changes in commitments during the first three months of 2018. Please refer to Note 6 - Commitments and Contingencies in the Company's 2017 Form 10-K for additional discussion of the Company's commitments.

#### Contingencies

The Company is subject to litigation and claims arising in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of any pending litigation and claims are not expected to have a material effect on the results of operations, the financial position, or the cash flows of the Company.

#### Note 7 - Compensation Plans

##### Performance Share Units

The Company grants performance share units (“PSUs”) to eligible employees as part of its long-term equity incentive compensation program. The number of shares of the Company’s common stock issued to settle PSUs ranges from zero to two times the number of PSUs awarded and is determined based on certain performance criteria over a three-year measurement period. The performance criteria for PSUs are based on a combination of the Company’s annualized Total Shareholder Return (“TSR”) for the performance period and the relative performance of the Company’s TSR compared with the annualized TSR of certain peer companies for the performance period. Compensation expense for PSUs is recognized within general and administrative and exploration expense over the vesting periods of the respective awards.

Total compensation expense recorded for PSUs was \$2.4 million and \$2.5 million for the three months ended March 31, 2018, and 2017, respectively. As of March 31, 2018, there was \$15.6 million of total unrecognized compensation expense related to non-vested PSU awards, which is being amortized through 2020. There have been no material changes to the outstanding and non-vested PSUs during the three months ended March 31, 2018.

##### Employee Restricted Stock Units

The Company grants restricted stock units (“RSUs”) to eligible employees as part of its long-term equity incentive compensation program. Each RSU represents a right to receive one share of the Company’s common stock upon settlement of the award at the end of the specified vesting period. Compensation expense for RSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the respective awards. Total compensation expense recorded for employee RSUs was \$2.7 million and \$2.5 million for the three months ended March 31, 2018, and 2017, respectively. As of March 31, 2018, there was \$16.2 million of total unrecognized compensation expense related to non-vested RSU awards, which is being amortized through 2020. There have been no material changes to the outstanding and non-vested RSUs during the three months ended March 31, 2018.

#### Note 8 - Pension Benefits

##### Pension Plans

The Company has a non-contributory defined benefit pension plan covering employees who meet age and service requirements (the “Qualified Pension Plan”). The Company also has a supplemental non-contributory pension plan covering certain management employees (the “Nonqualified Pension Plan” and together with the Qualified Pension Plan, the “Pension Plans”). Effective as of January 1, 2016, the Company froze the Pension Plans to new participants, and employees eligible to participate in the Pension Plans prior to them being frozen will continue to earn benefits.

## Components of Net Periodic Benefit Cost for the Pension Plans

The following table presents the components of the net periodic benefit cost for the Pension Plans:

	For the Three Months Ended March 31, 2018 2017 (in thousands)	
Service cost	\$1,660	\$2,050
Interest cost	673	727
Expected return on plan assets that reduces periodic pension benefit cost	(561 )	(559 )
Amortization of prior service cost	4	4
Amortization of net actuarial loss	324	396
Net periodic benefit cost	\$2,100	\$2,618

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of 10 percent of the greater of the benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants. As a result of the adoption of ASU 2017-07, the service cost component of net periodic benefit cost for the Pension Plans is presented as an operating expense within the general and administrative and exploration expense line items on the accompanying statements of operations while the other components of net periodic benefit cost for the Pension Plans are presented as non-operating expenses within the other non-operating income (expense), net line item on the accompanying statements of operations. Please refer to Note 1 - Summary of Significant Accounting Policies for further detail.

## Contributions

The Company contributed \$4.1 million to the Qualified Pension Plan during the three months ended March 31, 2018.



## Note 9 - Earnings Per Share

Basic net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average number of common shares outstanding for the respective period. Diluted net income or loss per common share is calculated by dividing adjusted net income or loss by the diluted weighted-average number of common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist primarily of non-vested RSUs, contingent PSUs, and shares into which the Senior Convertible Notes are convertible, which are measured using the treasury stock method. Shares of the Company's common stock traded at an average closing price below the \$40.50 conversion price for the three months ended March 31, 2018, and 2017, and therefore the Senior Convertible Notes had no dilutive impact. Please refer to Note 1 - Summary of Significant Accounting Policies in the Company's 2017 Form 10-K for additional detail on these potentially dilutive securities.

The following table sets forth the calculations of basic and diluted net income per common share:

	For the Three Months Ended March 31, 2018      2017 (in thousands, except per share data)	
Net income	\$317,401	\$74,434
Basic weighted-average common shares outstanding	111,696	111,258
Dilutive effect of non-vested RSUs and contingent PSUs	1,183	71
Dilutive effect of Senior Convertible Notes	—	—
Diluted weighted-average common shares outstanding	112,879	111,329
Basic net income per common share	\$2.84	\$0.67
Diluted net income per common share	\$2.81	\$0.67

## Note 10 - Derivative Financial Instruments

## Summary of Oil, Gas, and NGL Derivative Contracts in Place

The Company has entered into various commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. As of March 31, 2018, all derivative counterparties were members of the Company's credit facility lender group and all contracts were entered into for other-than-trading purposes. The Company's commodity derivative contracts consist of swap and collar arrangements for oil and gas, and swap arrangements for NGLs. In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference. For collar arrangements, the Company receives the difference between an agreed upon index and the floor price if the index price is below the floor price. The Company pays the difference between the agreed upon ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

As of March 31, 2018, the Company had commodity derivative contracts outstanding as summarized in the tables below:

## Oil Swaps

Contract Period	NYMEX WTI Weighted-Average	
	Volumes	Contract Price
	(MBbl)	(per Bbl)
Second quarter 2018	1,534	\$ 49.57
Third quarter 2018	1,769	\$ 49.77
Fourth quarter 2018	1,894	\$ 49.87
2019	1,940	\$ 50.70
Total	7,137	

## Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted- Average	
		Floor Price	Ceiling Price
	(MBbl)	(per Bbl)	(per Bbl)
Second quarter 2018	1,459	\$ 50.00	\$ 59.03
Third quarter 2018	1,948	\$ 50.00	\$ 58.61
Fourth quarter 2018	2,222	\$ 50.00	\$ 58.44
2019	5,908	\$ 47.65	\$ 59.19
Total	11,537		

## Oil Basis Swaps

Contract Period	Midland-Cushing Weighted-Average	
	Volumes	Contract Price <sup>(1)</sup>
	(MBbl)	(per Bbl)
Second quarter 2018	2,392	\$ (1.03 )
Third quarter 2018	3,018	\$ (1.06 )
Fourth quarter 2018	3,327	\$ (1.08 )
2019	5,788	\$ (1.09 )
Total	14,525	

<sup>(1)</sup> Represents the price differential between WTI prices at Midland, Texas and WTI prices at Cushing, Oklahoma.

## Gas Swaps

Contract Period	Sold	Weighted-Average	Purchased	Weighted-Average	Net
	Volumes	Contract Price	Volumes	Contract Price	Volumes
	(BBtu)	(per MMBtu)	(BBtu)	(per MMBtu)	(BBtu)
Second quarter 2018	23,507	\$ 3.31	(7,795 )	\$ 4.24	15,712
Third quarter 2018	24,627	\$ 3.29	(7,480 )	\$ 4.23	17,147
Fourth quarter 2018	25,856	\$ 3.29	(7,210 )	\$ 4.27	18,646
2019	41,394	\$ 3.76	(24,415 )	\$ 4.34	16,979
Total <sup>(1)</sup>	115,384		(46,900 )		68,484

<sup>(1)</sup> Total net volumes of gas swaps are comprised 100% of IF HSC.

## NGL Swaps

Contract Period	OPIS Purity Ethane Mont Belvieu		OPIS Propane Mont Belvieu Non-TET		OPIS Normal Butane Mont Belvieu Non-TET		OPIS Isobutane Mont Belvieu Non-TET		OPIS Natural Gasoline Mont Belvieu Non-TET	
	Volume (MMBbl)	Weighted-Average Contract Price (per Bbl)	Volume (MMBbl)	Weighted-Average Contract Price (per Bbl)	Volume (MMBbl)	Weighted-Average Contract Price (per Bbl)	Volume (MMBbl)	Weighted-Average Contract Price (per Bbl)	Volume (MMBbl)	Weighted-Average Contract Price (per Bbl)
Second quarter 2018	915	\$ 10.87	554	\$ 24.94	84	\$ 35.69	66	\$ 35.07	175	\$ 50.99
Third quarter 2018	1,033	\$ 10.99	610	\$ 24.27	93	\$ 35.70	70	\$ 35.07	202	\$ 51.13
Fourth quarter 2018	1,146	\$ 11.18	671	\$ 24.39	102	\$ 35.70	76	\$ 35.07	208	\$ 50.99
2019	3,533	\$ 12.31	1,503	\$ 27.83	154	\$ 35.64	117	\$ 35.70	197	\$ 50.93
2020	539	\$ 11.13	—	\$ —	—	\$ —	—	\$ —	—	\$ —
Total	7,166		3,338		433		329		782	

## Commodity Derivative Contracts Entered Into After March 31, 2018

Subsequent to March 31, 2018, the Company entered into various derivative contracts, as summarized below:

NYMEX WTI costless collar contracts for 2019 for a total of 2.1 MMBbl of oil production with contract floor prices ranging from \$50.00 per Bbl to \$55.00 per Bbl and contract ceiling prices ranging from \$66.60 per Bbl to \$68.62 per Bbl;

fixed price Midland-Cushing basis swap contract for 2019 for a total of 0.5 MMBbl of oil production at a contract price of (\$3.80) per Bbl;

fixed price Midland-Cushing basis swap contracts for 2020 for a total of 2.3 MMBbl of oil production at contract prices ranging from (\$0.80) per Bbl to (\$0.97) per Bbl; and

IF HSC costless collar contracts for 2019 for a total of 14,242 BBtu of gas production with contract floor prices of \$2.50 per MMBtu and contract ceiling prices ranging from \$2.83 per MMBtu to \$2.84 per MMBtu.

## Derivative Assets and Liabilities Fair Value

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The fair value of the commodity derivative contracts was a net liability of \$122.4 million as of March 31, 2018, and a net liability of \$139.4 million as of December 31, 2017.

The following table details the fair value of commodity derivative contracts recorded in the accompanying balance sheets, by category:

	As of March 31, 2018 (in thousands)	As of December 31, 2017
Derivative assets:		
Current assets	\$77,296	\$64,266
Noncurrent assets	35,128	40,362
Total derivative assets	\$112,424	\$104,628
Derivative liabilities:		
Current liabilities	\$181,068	\$172,582
Noncurrent liabilities	53,712	71,402
Total derivative liabilities	\$234,780	\$243,984

### Offsetting of Derivative Assets and Liabilities

As of March 31, 2018, and December 31, 2017, all derivative instruments held by the Company were subject to master netting arrangements with various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that settle on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company's derivative contracts:

	Derivative Assets		Derivative Liabilities	
	As of March 31, 2018	December 31, 2017	As of March 31, 2018	December 31, 2017
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	\$ 112,424	\$ 104,628	\$(234,780)	\$(243,984)
Amounts not offset in the accompanying balance sheets	(100,617)	(100,035)	100,617	100,035
Net amounts	\$ 11,807	\$ 4,593	\$(134,163)	\$(143,949)

The following table summarizes the components of the net derivative (gain) loss presented in the accompanying statements of operations:

	For the Three Months Ended March 31, 2018		2017
			(in thousands)
Derivative settlement (gain) loss:			
Oil contracts	\$20,748	\$9,084	
Gas contracts	(6,410)	(17,506)	
NGL contracts	10,190	8,415	
Total derivative settlement (gain) loss	\$24,528	\$(7)	
Net derivative (gain) loss:			
Oil contracts	\$13,966	\$(49,590)	
Gas contracts	9,990	(44,468)	
NGL contracts	(16,427)	(20,716)	
Total net derivative (gain) loss	\$7,529	\$(114,774)	

### Credit Related Contingent Features

As of March 31, 2018, and through the filing of this report, all of the Company's derivative counterparties were members of the Company's credit facility lender group. Under the Credit Agreement and derivative contracts, the Company is required to secure mortgages on assets having a value equal to at least 90 percent of the total PV-9 of the Company's proved oil and gas properties evaluated in the most recent reserve report.

## Note 11 - Fair Value Measurements

The Company follows fair value measurement accounting guidance for all assets and liabilities measured at fair value. This guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The fair value hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

Level 1 – quoted prices in active markets for identical assets or liabilities

Level 2 – quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable

Level 3 – significant inputs to the valuation model are unobservable

The following table is a listing of the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they are classified within the fair value hierarchy as of March 31, 2018:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives <sup>(1)</sup>	\$-\$112,424	\$—	
Total property and equipment, net <sup>(2)</sup>	\$-\$—		\$192,000
Liabilities:			
Derivatives <sup>(1)</sup>	\$-\$234,780	\$—	

<sup>(1)</sup> This represents a financial asset or liability that is measured at fair value on a recurring basis.

<sup>(2)</sup> This represents a non-financial asset that is measured at fair value on a nonrecurring basis.

The following table is a listing of the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they were classified within the fair value hierarchy as of December 31, 2017:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives <sup>(1)</sup>	\$-\$104,628	\$—	
Liabilities:			
Derivatives <sup>(1)</sup>	\$-\$243,984	\$—	

<sup>(1)</sup> This represents a financial asset or liability that is measured at fair value on a recurring basis.

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy.

## Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration forward commodity price curves, counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The commodity derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

Please refer to Note 10 - Derivative Financial Instruments and to Note 11 - Fair Value Measurements in the Company's 2017 Form 10-K for more information regarding the Company's derivative instruments.

## Proved and Unproved Oil and Gas Properties and Other Property and Equipment

**Proved oil and gas properties.** Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future cash flows to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts representative of the current operating environment, as selected by the Company's management. The calculation of the discount rates is based on the best information available and the rates used ranged from 10 percent to 15 percent based on the reservoir-specific weightings of future estimated proved and unproved cash flows as of March 31, 2018, and December 31, 2017. The Company believes the discount rates are representative of current market conditions and considers estimates of future cash payments, reserve categories, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The prices for oil and gas are forecast based on NYMEX strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecast using OPIS pricing, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. There were no impairments of proved properties during the three months ended March 31, 2018, or 2017.

**Unproved oil and gas properties.** Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. Lease acquisition costs that are not individually significant are aggregated by prospect and the portion of such costs estimated to be nonproductive prior to lease expiration are amortized over the appropriate period. The estimate of what could be nonproductive is based on historical trends or other information, including current drilling plans and the Company's intent to renew leases. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: remaining lease terms, future development plans, risk-weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by the Company or other market participants. During the three months ended March 31, 2018, the Company recorded \$5.6 million in abandonment and impairment of unproved properties expense related to lease expirations. There was no abandonment and impairment of unproved properties expense recorded during the three months ended March 31, 2017.

**Oil and gas properties held for sale.** Proved and unproved oil and gas properties classified as held for sale, including the corresponding asset retirement obligation liability, are valued using a market approach, based on an estimated net selling price, as evidenced by the most current bid prices received from third parties, if available. If an estimated selling price is not available, the Company utilizes the various income valuation techniques discussed above. Any initial write-down and subsequent changes to the fair value less estimated cost to sell is included within the net gain on divestiture activity line item in the accompanying statements of operations.

For the three months ended March 31, 2018, and 2017, write-downs to fair value less estimated costs to sell on assets held for sale totaled \$24.1 million and \$359.6 million, respectively. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions in the Company's 2017 Form 10-K for more information regarding the Company's oil and gas properties held for sale.



## Long-Term Debt

The following table reflects the fair value of the Senior Notes and Senior Convertible Notes measured using Level 1 inputs based on quoted secondary market trading prices. These notes were not presented at fair value on the accompanying balance sheets as of March 31, 2018, or December 31, 2017, as they were recorded at carrying value, net of any unamortized discounts and deferred financing costs. Please refer to Note 5 - Long-Term Debt for additional discussion.

	As of March 31, 2018		As of December 31, 2017	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(in thousands)			
6.50% Senior Notes due 2021	\$344,611	\$347,626	\$344,611	\$351,682
6.125% Senior Notes due 2022	\$561,796	\$563,200	\$561,796	\$571,627
6.50% Senior Notes due 2023	\$394,985	\$394,124	\$394,985	\$403,434
5.0% Senior Notes due 2024	\$500,000	\$466,750	\$500,000	\$483,440
5.625% Senior Notes due 2025	\$500,000	\$473,750	\$500,000	\$494,355
6.75% Senior Notes due 2026	\$500,000	\$497,500	\$500,000	\$516,350
1.50% Senior Convertible Notes due 2021	\$172,500	\$164,091	\$172,500	\$168,291



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

This discussion includes forward-looking statements. Please refer to Cautionary Information about Forward-Looking Statements at the end of this item for important information about these types of statements.

### Overview of the Company

#### General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. We currently have producing assets and significant acreage positions in the Midland Basin and Eagle Ford shale plays in Texas, and expect to complete the sale of our remaining position in North Dakota by the end of the second quarter of 2018. Our strategic objective is to be a premier operator of top tier assets. We seek to maximize the value of our assets by applying industry leading technology and outstanding operational execution. Our portfolio is comprised of unconventional resource prospects with expanding prospective drilling opportunities, which we believe provide for long-term production and reserves growth. We are focused on achieving high full-cycle economic returns on our investments and maintaining a strong balance sheet.

#### Outlook for 2018

Our priorities for 2018, as set at the beginning of the year, are to:

- continue generating high margin returns from top tier projects that drive cash flow growth;
- core up our portfolio to focus on assets that generate the highest returns; and
- improve our credit metrics and maintain strong financial flexibility.

With respect to our 2018 priorities, we are focused on continuing to demonstrate the significant value of our Midland Basin assets and coring up this position in order to maximize our long-term growth. Our operational execution thus far in our Midland Basin program continues to yield stronger than expected well results, which has been key to increasing oil production, both on an absolute and relative basis. Increasing oil production and improved realized prices for oil in the first quarter of 2018 have led to improved operating margins and positive cash flow growth.

We successfully closed our previously announced PRB Divestiture in the first quarter of 2018, for net divestiture proceeds at closing of \$490.8 million, subject to final purchase price adjustments. We also began marketing our non-core Bakken/Three Forks assets in Divide County, North Dakota and third-party operated Half East assets in Upton County, Texas. We have entered into definitive agreements for the sale of these properties for a total gross purchase price of \$292.3 million, subject to certain price adjustments. We expect both of these divestitures to close in the second quarter of 2018. Proceeds received from our PRB Divestiture, and expected proceeds from our Half East Divestiture and Divide County Divestiture, provide us with significant liquidity. We plan to use these proceeds to fund our Midland Basin and Eagle Ford shale capital programs, and for general corporate purposes, including debt reduction. Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions in Part I, Item 1 of this report for additional discussion.

Our capital program for 2018, excluding acquisitions, is expected to be approximately \$1.27 billion, of which approximately 80 percent will be invested in drilling and completion activities. We plan to allocate the majority of our 2018 capital to our Midland Basin program, which generates the highest margins and returns in our portfolio. Planned drilling and completion activity in the Eagle Ford shale will be partially funded by a third party as part of our previously announced joint venture agreement. By concentrating our capital on the highest return programs and operating at strong performance levels, we believe we will generate higher company-wide margins, while also creating greater cash flow growth and value creation for our stockholders. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our 2018 capital program.

#### Financial Results

We recorded net income of \$317.4 million, or \$2.81 per diluted share, for the three months ended March 31, 2018, compared with net income of \$74.4 million, or \$0.67 per diluted share, for the same period in 2017. Net income for the three months ended March 31, 2018, was driven largely by a net estimated gain of \$409.2 million recorded upon

closing the PRB Divestiture. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2018, and 2017 below for additional discussion regarding the components of net income for each period presented.

We had net cash provided by operating activities of \$140.1 million for the three months ended March 31, 2018, compared with \$135.0 million for the same period in 2017. Please refer to Overview of Liquidity and Capital Resources below for additional discussion of our sources and uses of cash.

Adjusted EBITDAX, a non-GAAP financial measure, for the three months ended March 31, 2018, was \$210.2 million, compared with \$172.0 million for the same period in 2017. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations of our net income and net cash provided by operating activities to adjusted EBITDAX.

#### Operational Activities

In our Midland Basin program, we operated nine drilling rigs and five completion crews for the majority of the first quarter of 2018. For the full year 2018, we anticipate our Midland Basin program will average approximately eight operated drilling rigs and four completion crews. During the first quarter of 2018, our operations continued to focus on delineating and developing the Lower Spraberry and Wolfcamp A and B shale intervals on our RockStar acreage in Howard and Martin Counties, Texas, and our Sweetie Peck acreage in Upton and Midland Counties, Texas. We expect to allocate approximately 86 percent of our budgeted 2018 drilling and completion capital to our Midland Basin program.

Subsequent to March 31, 2018, we expanded our core RockStar acreage position by acquiring approximately 760 contiguous net acres of unproved properties in Martin County, Texas, for cash consideration of \$24.6 million. Further, as discussed above, we expect to close on the sale of our non-core third-party operated Half East assets during the second quarter of 2018.

In our operated Eagle Ford shale program, we operated two drilling rigs and averaged one completion crew during the first quarter of 2018. For the full year 2018, we anticipate our Eagle Ford shale program will operate approximately one to two drilling rigs and one completion crew. Drilling and completion activities related to our previously announced joint venture agreement in a focused portion of our Eagle Ford North area continued throughout the first quarter of 2018. We expect the remaining wells associated with this joint venture to be drilled and completed in 2018, with little capital investment required on our part. We plan to allocate approximately 14 percent of our budgeted 2018 drilling and completion capital to our Eagle Ford shale program.

During the first quarter of 2018, we successfully closed on the sale of our previously announced PRB Divestiture for net divestiture proceeds of \$490.8 million, subject to final purchase price adjustments. In addition, we also announced that we entered into a definitive agreement for the sale of our remaining Bakken/Three Forks assets in Divide County, North Dakota, which we expect to close in the second quarter of 2018, subject to customary closing conditions.

The table below provides a summary of changes in our drilled but not completed well count and current year drilling and completion activity in our operated programs during the first quarter of 2018:

	Midland Basin		Eagle Ford Shale		Bakken/Three Forks <sup>(1)</sup>		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled but not completed at December 31, 2017	49	41	33	30	18	15	100	86
Wells drilled	35	33	11	8	—	—	46	41
Wells completed	(22)	(17)	(5)	(5)	—	—	(27)	(22)
Other <sup>(2)</sup>	—	1	—	—	—	—	—	1
Wells drilled but not completed at March 31, 2018	62	58	39	33	18	15	119	106

<sup>(1)</sup> We have entered into a definitive agreement to sell our remaining Bakken/Three Forks assets in Divide County, North Dakota, which we expect to close in the second quarter of 2018, subject to customary closing conditions.

<sup>(2)</sup> Reflects net working interest changes resulting from normal business operations.



## Production Results

The table below provides a regional breakdown of our production for the first quarter of 2018:

	Permian	South Texas & Gulf Coast	Rocky Mountain (1)	Total
Production:				
Oil (MMBbl)	3.3	0.4	0.6	4.3
Gas (Bcf)	5.6	18.7	0.9	25.2
NGLs (MMBbl)	—	1.6	—	1.7
Equivalent (MMBOE)	4.3	5.1	0.8	10.1
Avg. daily equivalents (MBOE/d)	47.3	56.9	8.5	112.7
Relative percentage	42	% 50	% 8	% 100

Note: Amounts may not calculate due to rounding.

(1) During the first quarter of 2018, we closed the PRB Divestiture and entered into a definitive agreement to sell our

Divide County assets, which we expect to close in the second quarter of 2018. Upon closing the Divide County Divestiture, we will no longer have meaningful production volumes from the Rocky Mountain region.

Production on an equivalent basis decreased 16 percent for the three months ended March 31, 2018, compared with the same period in 2017. Production declines were primarily a result of the divestiture of our outside-operated Eagle Ford shale assets, which occurred in the first quarter of 2017, and declining production from our retained operated Eagle Ford shale assets as a result of reduced capital investment. A significant portion of these production declines were offset by increased production from our Permian region, which increased 102 percent in the first quarter of 2018 compared with the same period in 2017. Please refer to A Three-Month Overview of Selected Production and Financial Information, Including Trends and Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2018, and 2017 below for additional discussion on production.

## Costs Incurred in Oil and Gas Producing Activities

Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed, totaled \$372.2 million for the three months ended March 31, 2018, and were incurred primarily in our Midland Basin and operated Eagle Ford shale programs.

## Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period, before the effects of derivative settlements, unless otherwise indicated. While quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location, and transportation differentials for these products.

The following table summarizes commodity price data, as well as the effects of derivative settlements, for the first quarter of 2018, as well as the fourth and first quarters of 2017:

	For the Three Months Ended		
	March 31, 2018	December 31, 2017	March 31, 2017
Oil (per Bbl):			
Average NYMEX contract monthly price	\$62.87	\$ 55.40	\$ 51.91
Realized price, before the effect of derivative settlements	\$61.25	\$ 53.32	\$ 47.55
Effect of oil derivative settlements	\$(4.86 )	\$( 4.42 )	\$( 2.58 )
Gas:			
Average NYMEX monthly settle price (per MMBtu)	\$3.00	\$ 2.93	\$ 3.32
Realized price, before the effect of derivative settlements (per Mcf)	\$3.14	\$ 3.09	\$ 2.98
Effect of gas derivative settlements (per Mcf)	\$0.25	\$ 0.94	\$ 0.52
NGLs (per Bbl):			
Average OPIS price <sup>(1)</sup>	\$30.87	\$ 32.12	\$ 26.74
Realized price, before the effect of derivative settlements	\$25.53	\$ 26.01	\$ 22.06
Effect of NGL derivative settlements	\$(6.09 )	\$( 7.17 )	\$( 2.88 )

Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline for all periods presented. This product mix represents the industry standard composite barrel and does not necessarily represent our product mix for NGL production. Realized prices reflect our actual product mix.

We expect future prices for oil, gas, and NGLs to continue to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil is affected by real or perceived geopolitical risks in various regions of the world as well as the relative strength of the United States dollar compared to other currencies. Oil markets have strengthened due to recent inventory drawdowns, but we expect oil prices to remain volatile due to uncertainty in global demand and easy access to new supply such as increases in oil production from United States shale. Oil prices began to increase at the end of 2017 as a result of the Organization of Petroleum Exporting Countries (“OPEC”) and several non-OPEC exporting countries agreeing to maintain previously agreed upon production cuts through 2018.

We expect gas prices to remain near current levels in the near term due to the abundance of supply relative to demand. Demand from increased liquefied natural gas (“LNG”) exports and gas exports to Mexico are expected to help balance supply.

We expect NGL prices to continue to benefit from increased demand from export and petrochemical markets while being offset by increased drilling activity.

The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of April 25, 2018, and March 31, 2018:

	As of April 25, 2018	As of March 31, 2018
NYMEX WTI oil (per Bbl)	\$65.98	\$63.07
NYMEX Henry Hub gas (per MMBtu)	\$2.88	\$2.88
OPIS NGLs (per Bbl)	\$30.23	\$29.29

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives. The amount of our production covered by derivatives is driven by the amount of debt on our balance sheet, the level of capital commitments and long-term obligations we have in place, and our ability to enter into favorable derivative commodity contracts. With our current derivative contracts, we believe we have partially reduced our exposure to volatility in commodity prices in the near term. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil prices while also setting a price floor for a portion of our oil production. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report and to Commodity Price Risk in Overview of Liquidity and Capital Resources below for additional information regarding our oil, gas, and NGL derivatives.

## Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information for the three months ended March 31, 2018, and the immediately preceding three quarters. A detailed discussion follows.

	For the Three Months Ended			
	March 31, 2018	December 31, 2017	September 30, 2017	June 30, 2017
	(in millions)			
Production (MMBOE)	10.1	10.4	10.7	11.3
Oil, gas, and NGL production revenue	\$382.9	\$341.2	\$294.5	\$284.9
Oil, gas, and NGL production expense	\$120.9	\$122.8	\$122.7	\$124.4
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	\$130.5	\$131.4	\$134.6	\$153.2
Exploration <sup>(1)</sup>	\$13.7	\$15.8	\$14.1	\$13.0
General and administrative <sup>(1)</sup>	\$27.7	\$32.7	\$27.6	\$28.2
Net income (loss)	\$317.4	\$(26.3)	\$(89.1)	\$(119.9)

Note: Amounts may not calculate due to rounding.

Certain prior period amounts have been adjusted to conform to the current period presentation on the condensed <sup>(1)</sup> consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.

## Selected Performance Metrics

	For the Three Months Ended			
	March 31, 2018	December 31, 2017	September 30, 2017	June 30, 2017
Average net daily production equivalent (MBOE per day)	112.7	112.6	116.0	124.6
Lease operating expense (per BOE)	\$4.95	\$5.10	\$4.81	\$4.11
Transportation costs (per BOE)	\$4.63	\$5.01	\$5.24	\$5.71
Production taxes as a percent of oil, gas, and NGL production revenue	4.4 %	4.3 %	4.2 %	4.0 %
Ad valorem tax expense (per BOE)	\$0.67	\$0.33	\$0.29	\$0.16
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	\$12.87	\$12.69	\$12.61	\$13.52
General and administrative (per BOE) <sup>(1)</sup>	\$2.73	\$3.15	\$2.58	\$2.49

Note: Amounts may not calculate due to rounding.

Certain prior period amounts have been adjusted to conform to the current period presentation on the condensed <sup>(1)</sup> consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.

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A Three-Month Overview of Selected Production and Financial Information, Including Trends

	For the Three Months Ended March 31,		Amount	Percent	
	2018	2017	Change	Change	
			Between	Between	
			Periods	Periods	
Net production volumes: <sup>(1)</sup>					
Oil (MMBbl)	4.3	3.5	0.7	21	%
Gas (Bcf)	25.2	33.9	(8.7)	(26)	%
NGLs (MMBbl)	1.7	2.9	(1.2)	(43)	%
Equivalent (MMBOE)	10.1	12.1	(2.0)	(16)	%
Average net daily production: <sup>(1)</sup>					
Oil (MBbl per day)	47.4	39.2	8.2	21	%
Gas (MMcf per day)	280.2	376.6	(96.4)	(26)	%
NGLs (MBbl per day)	18.6	32.5	(13.9)	(43)	%
Equivalent (MBOE per day)	112.7	134.4	(21.7)	(16)	%
Oil, gas, and NGL production revenue (in millions): <sup>(1)</sup>					
Oil production revenue	\$261.1	\$167.6	\$93.4	56	%
Gas production revenue	79.1	101.2	(22.0)	(22)	%
NGL production revenue	42.7	64.4	(21.7)	(34)	%
Total oil, gas, and NGL production revenue	\$382.9	\$333.2	\$49.7	15	%
Oil, gas, and NGL production expense (in millions): <sup>(1)</sup>					
Lease operating expense	\$50.2	\$46.1	\$4.0	9	%
Transportation costs	46.9	71.1	(24.2)	(34)	%
Production taxes	17.0	14.1	2.9	21	%
Ad valorem tax expense	6.8	6.7	0.1	2	%
Total oil, gas, and NGL production expense	\$120.9	\$138.0	\$(17.2)	(12)	%
Realized price (before the effect of derivative settlements):					
Oil (per Bbl)	\$61.25	\$47.55	\$13.70	29	%
Gas (per Mcf)	\$3.14	\$2.98	\$0.16	5	%
NGLs (per Bbl)	\$25.53	\$22.06	\$3.47	16	%
Per BOE	\$37.76	\$27.55	\$10.21	37	%
Per BOE data:					
Production costs:					
Lease operating expense	\$4.95	\$3.82	\$1.13	30	%
Transportation costs	\$4.63	\$5.88	\$(1.25)	(21)	%
Production taxes	\$1.68	\$1.17	\$0.51	44	%
Ad valorem tax expense	\$0.67	\$0.55	\$0.12	22	%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	\$12.87	\$11.39	\$1.48	13	%
General and administrative <sup>(2)</sup>	\$2.73	\$2.38	\$0.35	15	%
Derivative settlement loss <sup>(3)</sup>	\$(2.42)	\$—	\$(2.42)	(100)	%
Earnings per share information:					
Basic net income per common share	\$2.84	\$0.67	\$2.17	324	%
Diluted net income per common share	\$2.81	\$0.67	\$2.14	319	%
Basic weighted-average common shares outstanding (in thousands)	111,696	111,258	438	—	%
Diluted weighted-average common shares outstanding (in thousands)	112,879	111,329	1,550	1	%





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- (1) Amount and percentage changes may not calculate due to rounding.  
The prior period has been adjusted to conform to the current period presentation on the condensed consolidated
  - (2) financial statements. Please refer to Recently Issued Accounting Standards in Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.
  - (3) Derivative settlements for the three months ended March 31, 2018, and 2017, are included within the net derivative (gain) loss line item in the accompanying statements of operations.

We present per BOE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis. Average net daily production for the three months ended March 31, 2018, decreased 16 percent compared with the same period in 2017. This decrease was primarily due to the divestiture of our outside-operated Eagle Ford shale assets in the first quarter of 2017, and declining production from our retained operated Eagle Ford shale assets as a result of reduced capital investment. For the full year 2018, we expect total production to decrease slightly compared with 2017, as anticipated production increases in our Midland Basin program are expected to be offset by production decreases resulting from our 2017 and 2018 divestiture activities and declines from our operated Eagle Ford shale program. On a retained asset basis, we expect production to increase and the percentage of oil relative to our total product mix to also increase in 2018 compared with 2017. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2018, and 2017 below for additional discussion.

Changes in production volumes, revenues, and costs are directly influenced by the volatility of commodity prices for the products we produce, fluctuations in costs necessary to develop and operate our properties, our ability to increase efficiencies in operations, and changes in our overall asset portfolio. Our realized price before the effects of derivative settlements on a per BOE basis for the three months ended March 31, 2018, increased 37 percent, compared with the same period in 2017. For the three months ended March 31, 2018, we realized a loss of \$2.42 per BOE on the settlement of our derivative contracts. For the three months ended March 31, 2017, we had a minimal gain on the settlement of our derivative contracts, which resulted in no gain on a per BOE basis.

Lease operating expense ("LOE") on a per BOE basis increased 30 percent, for the three months ended March 31, 2018, compared with the same period in 2017. The increase in LOE on a per BOE basis was driven by the increase in oil production as a percentage of our total product mix, and the divestiture of our outside-operated Eagle Ford shale assets in the first quarter of 2017, which had lower average lifting costs. We expect LOE on a per BOE basis to be higher in 2018 compared with 2017 as our product mix continues to shift toward more oil production, which typically has higher LOE per BOE. We expect to experience volatility in our LOE as a result of changes in industry activity and the effects this has on service provider costs, changes in total production, changes in our overall production mix, and timing of workover projects.

Transportation expense on a per BOE basis decreased 21 percent, for the three months ended March 31, 2018, compared with the same period in 2017. This decrease was primarily driven by the sale of our outside-operated Eagle Ford shale assets in the first quarter of 2017, which had higher average transportation costs. Going forward, we expect total transportation expense to fluctuate in line with changes in production from our operated Eagle Ford shale program as these assets incur the majority of our transportation costs. On a per BOE basis, we expect transportation costs to decrease in 2018 as production from our Midland Basin assets becomes a larger portion of our total production. The majority of our Midland Basin production is currently sold at the wellhead, and therefore, we incur minimal transportation expense on these assets.

Production taxes on a per BOE basis increased 44 percent, for the three months ended March 31, 2018, compared with the same period in 2017, due to a 37 percent increase in our realized price before the effect of derivative settlements and slight increase in our production tax rate. Our production tax rate for the three months ended March 31, 2018, was 4.4 percent, compared with 4.2 percent, for the same period in 2017. This increase in our company-wide production tax rate is primarily a result of the increase in oil production as a percentage of total production. We generally expect production tax expense to trend with oil, gas, and NGL production revenue on an absolute and per BOE basis. Product mix, the location of production, and incentives to encourage oil and gas development can also impact the amount of production tax we recognize.

Ad valorem tax expense on a per BOE basis increased 22 percent for the three months ended March 31, 2018, compared with the same period in 2017 as a result of changes in our asset and production base and increased commodity price assumptions used in 2018 property tax valuations. As a result, we expect an increase in ad valorem tax expense for the full year 2018 as compared with 2017 on both an absolute and per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion (“DD&A”) expense on a per BOE basis increased 13 percent, for the three months ended March 31, 2018, compared with the same period in 2017. This increase is primarily a result of an increase in production volumes from our Midland Basin assets, which have higher depletion rates than our Eagle Ford shale and Divide County assets. Our DD&A rate fluctuates as a result of impairments, divestiture activity, changes in our production mix, and changes in our total estimated proved reserve volumes. In general, we expect DD&A expense on a per BOE basis for the full year 2018 to increase slightly compared with 2017 as production from our Midland Basin assets continues to increase on an absolute and relative basis.

General and administrative (“G&A”) expense on a per BOE basis increased 15 percent for the three months ended March 31, 2018, compared with the same period in 2017 due to the decrease in production volumes as a result of divestitures. We expect G&A expense on an absolute basis to increase for the full year 2018 compared with 2017 due to an anticipated increase in average headcount. We expect G&A expense on a per BOE basis in 2018 to also increase compared with 2017 as a result of increased G&A expense on an absolute basis.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2018, and 2017 below for additional discussion on operating expenses.

Please refer to Note 9 - Earnings Per Share in Part I, Item 1 of this report for discussion of our basic and diluted net income per common share calculations.

Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2018, and 2017

Net equivalent production, production revenue, and production expense

The following table presents the regional changes in our net equivalent production, production revenue, and production expense between the three months ended March 31, 2018, and 2017:

	Net Equivalent Production Increase (Decrease)  (MMBOE)	Production Revenue Increase (Decrease)  (in millions)	Production Expense Increase (Decrease)  (in millions)
Permian	2.1	\$ 137.8	\$ 21.0
South Texas & Gulf Coast	(3.7 )	(76.3 )	(34.8 )
Rocky Mountain	(0.4 )	(11.8 )	(3.4 )
Total	(2.0 )	\$ 49.7	\$ (17.2 )

For the three months ended March 31, 2018, compared with the same period in 2017, we experienced a 16 percent decrease in net equivalent production volumes primarily as a result of divestiture activity and declining production from our retained operated Eagle Ford shale assets as a result of reduced capital investment. Decreases in production volumes were offset by a 37 percent increase in realized prices on a per BOE basis, resulting in an overall 15 percent increase in oil, gas, and NGL production revenues in the first quarter of 2018 compared with the same period in 2017. Production expense for the three months ended March 31, 2018, compared with the same period in 2017, decreased 12 percent primarily as a result of decreased production volumes related to divestiture activity, as discussed above. In our Permian region, net equivalent production volumes increased 2.1 MMBOE, or 102 percent, in the first quarter of 2018 compared with the same period in 2017. This drove total oil production as a percentage of our overall product mix to increase from 29 percent in the first quarter of 2017 to 42 percent in the first quarter of 2018. Please refer to A Three-Month Overview of Selected Production and Financial Information, Including Trends above for discussion of trends on a per BOE basis.

## Net gain on divestiture activity

For the Three  
Months  
Ended  
March 31,  
2018 2017  
(in millions)

Net gain on divestiture activity \$385.4 \$37.5

The \$385.4 million net gain on divestiture activity recorded for the three months ended March 31, 2018, was primarily the result of a \$409.2 million estimated net gain recorded for our PRB Divestiture during the first quarter of 2018, which was partially offset by a \$24.1 million write-down on certain assets held for sale. The \$37.5 million net gain on divestiture activity recorded for the three months ended March 31, 2017, was primarily the result of a \$398.1 million net gain recorded on the sale of our outside-operated Eagle Ford shale assets, mostly offset by a write-down to fair value less estimated selling costs recorded on assets held for sale.

Please refer to Note 3 - Divestitures, Assets Held for Sale, and Acquisitions in Part I, Item 1 of this report for additional discussion.

## Depletion, depreciation, amortization, and asset retirement obligation liability accretion

For the Three  
Months Ended  
March 31,  
2018 2017  
(in millions)

Depletion, depreciation, amortization, and asset retirement obligation liability accretion \$130.5 \$137.8

DD&A expense decreased five percent for the three months ended March 31, 2018, compared with the same period in 2017, due to the decline in our production volumes and the impact of assets sold and assets held for sale. Please refer to the section A Three-Month Overview of Selected Production and Financial Information, Including Trends above for further discussion of DD&A expense on a per BOE basis.

## Exploration

For the  
Three  
Months  
Ended  
March 31,  
2018 2017  
(in millions)

Exploration <sup>(1)</sup> \$13.7 \$11.8

<sup>(1)</sup> The prior period has been adjusted to conform to the current period presentation on the condensed consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.

Exploration expense increased 16 percent for the three months ended March 31, 2018, compared with the same period in 2017, due to increased expenditures for geological and geophysical activity on our Midland Basin assets. As we continue our focus on testing and delineating our Midland Basin acreage, we expect increased exploration activity and related expenses for the full year 2018 compared with 2017. Exploration expense may vary depending upon allocated overhead and exploratory dry hole expense.

## Abandonment and impairment of unproved properties

For the Three  
Months  
Ended  
March 31,  
2018 2017  
(in millions)

Abandonment and impairment of unproved properties \$ 5.6 \$ —

Unproved property impairments recorded for the three months ended March 31, 2018, related to lease expirations. There were no unproved property impairments recorded for the three months ended March 31, 2017.

We expect that proved property impairments are more likely to occur in periods of declining or depressed commodity prices, and unproved property impairments to fluctuate with the timing of lease expirations, unsuccessful exploration activities, and changing economics associated with decreases in commodity prices. Additionally, changes in drilling plans, downward engineering revisions, or unsuccessful exploration efforts may result in proved and unproved property impairments. Any amount of future impairment is difficult to predict, but based on updated commodity price assumptions as of April 25, 2018, we do not expect any material impairments in the second quarter of 2018 resulting from commodity price impacts. Abandonment and impairment of unproved properties expense will be recognized as additional lease expirations are identified.

## General and administrative

For the  
Three  
Months  
Ended  
March 31,  
2018 2017  
(in millions)

General and administrative <sup>(1)</sup> \$27.7 \$28.8

<sup>(1)</sup> The prior period has been adjusted to conform to the current period presentation on the condensed consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.

G&A expense decreased slightly for the three months ended March 31, 2018, compared with the same period in 2017. This decrease was primarily driven by the additional costs we incurred in the first quarter of 2017 as a result of large asset divestitures in late 2016 and early 2017, which increased certain G&A costs, including employee relocation expenditures. Please refer to the section A Three-Month Overview of Selected Production and Financial Information, Including Trends above for further discussion of G&A expense on an absolute and per BOE basis.

## Net derivative (gain) loss

For the Three  
Months  
Ended  
March 31,  
2018 2017  
(in millions)

Net derivative (gain) loss \$7.5 \$(114.8)

We recognized a \$7.5 million derivative loss for the three months ended March 31, 2018, due largely to a \$24.5 million realized loss for contracts settled during the three months ended March 31, 2018, partially offset by a \$17.0 million increase in the fair value of contracts settling subsequent to March 31, 2018. We recognized a \$114.8 million derivative gain for the three months ended March 31, 2017, which is primarily a result of a \$94.3 million mark-to-market gain recorded on contracts remaining as of March 31, 2017, due to a decrease in commodity strip prices from December 31, 2016.

Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information.

## Interest expense

For the Three  
Months Ended  
March 31,  
2018 2017  
(in millions)

Interest expense \$(43.1) \$(47.0)

The eight percent decrease in interest expense for the three months ended March 31, 2018, compared with the same period in 2017, was primarily driven by an increase in capitalized interest as a result of our higher level of development activity. Please refer to Note 5 - Long-Term Debt in Part I, Item I of this report and Overview of Liquidity and Capital Resources below for additional information.

## Income tax expense

For the Three  
Months Ended  
March 31,  
2018 2017  
(in millions,  
except tax rate)

Income tax expense \$(99.0) \$(44.5)

Effective tax rate 23.8 % 37.4 %

The decrease in the effective tax rate for the three months ended March 31, 2018, compared with the same period in 2017, was due to the decrease in the federal tax rate as a result of the 2017 Tax Act, which reduced the highest marginal corporate tax rate from 35 percent to 21 percent. Income tax effects from share-based compensation were partially offset by state rate differences, valuation allowances and other small permanent items. Please refer to Overview of Liquidity and Capital Resources below as well as Note 4 - Income Taxes in Part I, Item 1 of this report for additional discussion.

## Overview of Liquidity and Capital Resources

Based on the current commodity price environment, we believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We continue to manage the duration and level of our drilling and completion service commitments to maintain the flexibility to adjust our activity and capital expenditures during periods of prolonged weak commodity prices or to respond should commodity prices recover further.

## Sources of Cash

We currently expect our 2018 capital program to be funded by cash flows from operations and proceeds from the divestiture of properties. As of March 31, 2018, our cash balance totaled \$643.3 million, which includes the net divestiture proceeds we received at closing from the PRB Divestiture of \$490.8 million, subject to final purchase price adjustments. As of March 31, 2018, the combination of our cash balance with our \$924.8 million of available borrowing capacity under our Credit Agreement, resulted in \$1.6 billion in liquidity.

Although we anticipate cash flows from operations and divestiture proceeds will be sufficient to fund our expected 2018 capital program, we may also elect to borrow under our Credit Agreement and/or raise funds through debt or equity financings or from other sources. Further, we may enter into additional carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. See Credit Agreement below for discussion of the increase in our borrowing base in early 2018. Our borrowing base could be reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt. If we raise additional funds through the issuance of equity or convertible debt securities, the percentage ownership of our current stockholders could be diluted, and these newly-issued securities may have rights, preferences, or privileges senior to those of existing stockholders. Any future downgrades in our credit ratings could make it more difficult or expensive for us to borrow additional funds. All of our sources of liquidity can be affected by the general condition of the broader economy and by fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry.





We have no control over the market prices for oil, gas, or NGLs, although we may be able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information about our oil, gas, and NGL derivative contracts currently in place and the timing of settlement of those contracts.

The enactment of the 2017 Tax Act reduced our highest marginal corporate tax rate for 2018 and future years from 35 percent to 21 percent. It also eliminated the domestic production activities deduction for all taxpayers, the alternative minimum tax ("AMT") for corporate taxpayers, and may impact our ability to deduct interest expense in future years. However, it did not impact current tax deductions for intangible drilling costs, percentage depletion, or amortization of geological and geophysical expenses, and it will allow us the option to expense 100 percent of our equipment acquisition costs in future years. In general, we believe the enactment of the 2017 Tax Act will have a positive impact on our future operating cash flows.

#### Credit Agreement

Our Credit Agreement provides for a maximum loan amount of \$2.5 billion and has a maturity date of December 10, 2019. As of March 31, 2018, our borrowing base and aggregate lender commitments were \$925 million, which were unchanged from December 31, 2017. Subsequent to March 31, 2018, as part of the regular, semi-annual borrowing base redetermination process, our borrowing base and aggregate lender commitments were increased to \$1.4 billion and \$1.0 billion, respectively. The increase in the borrowing base was primarily driven by the increased value of our estimated proved reserves at December 31, 2017. The next scheduled redetermination date is October 1, 2018.

We had no outstanding balance under our Credit Agreement as of March 31, 2018, or as of the filing of this report. No individual bank participating in our Credit Agreement represents more than 10 percent of the lender commitments under the Credit Agreement. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our Credit Agreement as of April 25, 2018, March 31, 2018, and December 31, 2017.

We must comply with certain financial and non-financial covenants under the Credit Agreement, including covenants limiting dividend payments and requiring us to maintain certain financial ratios, as defined by the Credit Agreement. Certain financial covenants under the Credit Agreement require, as of the last day of each fiscal quarter, our (a) ratio of senior secured debt to 12-month trailing adjusted EBITDAX to be not more than 2.75 to 1.0; (b) adjusted current ratio to be not less than 1.0 to 1.0; and (c) ratio of 12-month trailing adjusted EBITDAX to interest expense to be not less than 2.0 to 1.0. We were in compliance with all financial and non-financial covenants under the Credit Agreement as of March 31, 2018, and through the filing of this report. Please refer to the caption Non-GAAP Financial Measures below for the calculation of adjusted EBITDAX and reconciliations of net income and net cash provided by operating activities to adjusted EBITDAX.

We had no credit facility activity during the three months ended March 31, 2018, due to our cash balance resulting primarily from proceeds received from divestiture activity. Cash flows provided by our operating activities, divestiture proceeds, capital markets activity, and the amount of our capital expenditures, including acquisitions, all impact the amount we borrow under our credit facility.

### Weighted-Average Interest Rates

Our weighted-average interest rates include paid and accrued interest, fees on the unused portion of the aggregate commitment amount under the Credit Agreement, letter of credit fees, the non-cash amortization of deferred financing costs, and the non-cash amortization of the discount related to the Senior Convertible Notes. Our weighted-average borrowing rate includes paid and accrued interest only.

The following table presents our weighted-average interest rate and our weighted-average borrowing rate for the three months ended March 31, 2018, and 2017:

	For the Three Months Ended March 31, 2018 2017	
Weighted-average interest rate	6.5%	6.6%
Weighted-average borrowing rate	5.9%	5.8%

The weighted-average interest rate and weighted-average borrowing for the three months ended March 31, 2018, remained consistent as compared with the same period in 2017. We would expect our weighted-average interest and borrowing rates to fluctuate based on the timing and amount of Senior Notes redemptions, changes in our aggregate lender commitment amount on our credit facility, and the average balance on our credit facility. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion.

### Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of operating and general and administrative costs, income taxes, dividends, and debt obligations, including interest. Expenditures for the acquisition, exploration, and development of oil and gas properties are the primary use of our capital resources. During the three months ended March 31, 2018, we spent \$301.5 million on capital expenditures. This amount differs from the costs incurred amount, which is accrual-based and includes asset retirement obligations, geological and geophysical expenses, and exploration overhead amounts.

The amount and allocation of our future capital expenditures will depend upon a number of factors, including the number and size of acquisition opportunities, our cash flows from operating, investing, and financing activities, and our ability to assimilate acquisitions and execute our drilling program. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital, and the timing and results of our exploration and development activities may lead to changes in funding requirements for future development. We periodically review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material. Repurchases or exchanges are reviewed as part of the allocation of our capital. As part of our strategy for 2018, we will focus on improving our debt metrics and potentially reducing outstanding debt. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion.

As of the filing of this report, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program, subject to the approval of our Board of Directors. Shares may be repurchased from time to time in the open market, or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our Credit Agreement, the indentures governing our Senior Notes, the indenture governing our Senior Convertible Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. Our Board of Directors periodically reviews this program as part of the allocation of our capital. We currently do not plan to repurchase any outstanding shares of common stock during 2018.

Analysis of Cash Flow Changes Between the Three Months Ended March 31, 2018, and 2017



The following tables present changes in cash flows between the three months ended March 31, 2018, and 2017, for our operating, investing, and financing activities. The three months ended March 31, 2017, have been adjusted to conform to the current period presentation. Please refer to Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion of adjustments made as a result of adopting new accounting standards. The analysis following each table should be read in conjunction with our accompanying statements of cash flows in Part I, Item 1 of this report.

#### Operating activities

For the Three  
Months Ended  
March 31,  
2018 2017  
(in millions)

Net cash provided by operating activities \$140.1 \$135.0

Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, increased \$21.9 million for the three months ended March 31, 2018, compared with the same period in 2017, primarily as a result of an increase in our realized price, after the effects of derivative settlements. This increase was partially offset by a \$6.5 million increase in cash paid for LOE and ad valorem taxes for the three months ended March 31, 2018, compared with the same period in 2017. Net cash provided by operating activities is affected by working capital changes and the timing of cash receipts and disbursements.

#### Investing activities

For the Three  
Months Ended  
March 31,  
2018 2017  
(in millions)

Net cash provided by investing activities \$189.3 \$514.8

The decrease in cash flows from investing activities for the three months ended March 31, 2018, compared with the same period in 2017 is largely due to decreased divestiture cash proceeds of \$253.5 million. We received divestiture cash proceeds of \$490.8 million in the first quarter of 2018, primarily from our PRB Divestiture, compared to \$744.3 million in the first quarter of 2017, primarily from the sale of our outside-operated Eagle Ford shale assets. Further, we incurred capital expenditures, including acquisition of proved and unproved properties, of \$301.5 million during the first quarter of 2018, an increase of \$72.0 million compared with the same period in 2017. The increase is due to higher capital expenditures in our Midland Basin program partially offset by lower acquisition expenditures as compared with the same period in 2017.

#### Financing activities

For the  
Three  
Months  
Ended  
March  
31,  
2018 2017  
(in  
millions)

Net cash used in financing activities \$— \$(2.5)

We had no financing activities in the first quarter of 2018. During the three months ended March 31, 2017, we paid \$2.3 million for the repurchase of a portion of our Senior Notes at a slight premium.

#### Interest Rate Risk

We are exposed to market risk due to the floating interest rate associated with any outstanding balance on our revolving credit facility. As of March 31, 2018, and through the filing of this report, we had a zero balance on our credit facility. Our Credit Agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period of up to six months. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate Senior Notes or fixed-rate Senior Convertible Notes, but can impact their fair market values. As of March 31, 2018, our outstanding fixed-rate debt totaled approximately \$3.0 billion. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion on the fair values of our Senior Notes and Senior Convertible Notes.

#### Commodity Price Risk

The prices we receive for our oil, gas, and NGL production directly impact our revenue, overall profitability, access to capital, and future rate of growth. Oil, gas, and NGL prices are subject to wide fluctuations in response to changes in supply and demand and other factors. The markets for oil, gas, and NGLs have been volatile, especially over the last several years, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Based on our production for the three months ended March 31, 2018, a 10 percent decrease in our average realized oil, gas, and NGL prices before the effects of derivative settlements would have reduced our oil, gas, and NGL production revenues by approximately \$26.1 million, \$7.9 million, and \$4.3 million, respectively. If commodity prices had been 10 percent lower, our derivative settlements would have been higher, partially offsetting the decrease in production revenues quantified above.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. The fair value of our commodity derivative contracts are largely determined by estimates of the forward curves of the relevant price indices. As of March 31, 2018, a 10 percent increase or decrease in the forward curves associated with our oil, gas, and NGL commodity derivative instruments would have changed our net liability positions by approximately \$89.1 million, \$19.5 million, and \$25.4 million, respectively.

#### Off-Balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities (“SPEs”), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

We evaluate our transactions to determine if any variable interest entities exist. If we determine that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements. We have not been involved in any unconsolidated SPE transactions during the three months ended March 31, 2018, or through the filing of this report.

#### Critical Accounting Policies and Estimates

Please refer to the corresponding section in Part II, Item 7 and to Note 1 - Summary of Significant Accounting Policies included in Part II, Item 8 of our 2017 Form 10-K for discussion of our accounting policies and estimates.

#### New Accounting Pronouncements

Please refer to Note 1 - Summary of Significant Accounting Policies under Part I, Item 1 of this report for new accounting pronouncements.

#### Non-GAAP Financial Measures

Adjusted EBITDAX represents net income (loss) before interest expense, interest income, income taxes, depletion, depreciation, amortization and asset retirement obligation liability accretion expense, exploration expense, property abandonment and impairment expense, non-cash stock-based compensation expense, derivative gains and losses net of settlements, gains and losses on divestitures, gains and losses on extinguishment of debt, and certain other items. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally one-time in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that we present because we believe it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our Credit Agreement based on adjusted EBITDAX ratios as further described in Credit Agreement in Overview of Liquidity and Capital Resources above. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all, items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies. Our credit facility provides a material source of liquidity for us. Under the terms of our Credit Agreement, if we failed to comply with the covenants that establish a maximum permitted ratio of senior secured debt to adjusted EBITDAX and a minimum permitted ratio of adjusted EBITDAX to interest, we would be in default, an event that would prevent us from borrowing under our credit facility and would therefore materially limit our sources of liquidity. In addition, if we are in default under our credit facility and are unable to obtain a waiver of that default from our lenders, lenders under that facility and under the indentures governing our outstanding Senior Notes and Senior Convertible Notes would be entitled to exercise all of their remedies for default.

The following table provides reconciliations of our net income (GAAP) and net cash provided by operating activities (GAAP) to adjusted EBITDAX (non-GAAP) for the periods presented:

	For the Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Net income (GAAP)	\$317,401	\$74,434
Interest expense	43,085	46,953
Interest income <sup>(1)</sup>	(849 )	(335 )
Income tax expense	98,991	44,506
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	130,473	137,812
Exploration <sup>(2) (3)</sup>	12,411	10,409
Abandonment and impairment of unproved properties	5,625	—
Stock-based compensation expense	5,412	5,455
Net derivative (gain) loss	7,529	(114,774 )
Derivative settlement gain (loss)	(24,528 )	7
Net gain on divestiture activity	(385,369 )	(37,463 )
Loss on extinguishment of debt	—	35
Other	7	4,986
Adjusted EBITDAX (non-GAAP) <sup>(3)</sup>	210,188	172,025
Interest expense	(43,085 )	(46,953 )
Interest income <sup>(1)</sup>	849	335
Income tax expense	(98,991 )	(44,506 )
Exploration <sup>(2) (3)</sup>	(12,411 )	(10,409 )
Amortization of debt discount and deferred financing costs	3,866	4,946
Deferred income taxes	98,366	33,225
Other, net <sup>(3)</sup>	(2,534 )	(1,610 )
Changes in current assets and liabilities	(16,113 )	27,926
Net cash provided by operating activities (GAAP) <sup>(3)</sup>	\$140,135	\$134,979

<sup>(1)</sup> Interest income is included within the other non-operating income (expense), net line item on the accompanying statements of operations in Part I, Item 1 of this report.

<sup>(2)</sup> Stock-based compensation expense is a component of exploration expense and general and administrative expense on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations for the component of stock-based compensation expense recorded to exploration expense.

<sup>(3)</sup> Certain prior period amounts have been adjusted to conform to the current period presentation on the condensed consolidated financial statements. Please refer to Note 1 - Summary of Significant Accounting Policies in Part I, Item 1 of this report for additional discussion.



### Cautionary Information about Forward-Looking Statements

This report contains “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 (the “Exchange Act”). All statements, other than statements of historical facts, included in this report that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words “anticipate,” “assume,” “believe,” “budget,” “estimate,” “expect,” “foresee,” “intend,” “pending,” “plan,” “project,” “will,” and similar expressions are intended to identify forward-looking statements.

Forward-looking statements appear throughout this report, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- the drilling of wells and other exploration and development activities and plans, as well as possible or expected acquisitions or divestitures;
- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those reserve estimates;
- future oil, gas, and NGL production estimates;
- cash flows, anticipated liquidity, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties; and
- other similar matters such as those discussed in the Management’s Discussion and Analysis of Financial Condition and Results of Operations section in Part I, Item 2 of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Some of these risks are described in the Risk Factors section in Part I, Item 1A of our 2017 Form 10-K, and include such factors as:

- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- weakness in economic conditions and uncertainty in financial markets;
- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital required to develop and/or replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- our ability to attract and retain key personnel;
- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves;
  - the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on outside-operated properties;
- our reliance on the skill and expertise of third-party service providers on our operated properties;
- the possibility that title to properties in which we claim an interest may be defective;
- our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;

the uncertainties associated with acquisitions, divestitures, joint ventures, farm-downs, farm-outs and similar transactions with respect to certain assets, including whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;

the uncertainties associated with enhanced recovery methods;

our commodity derivative contracts may result in financial losses or may limit the prices we receive for oil, gas, and NGL sales;

the inability of one or more of our service providers, customers, or contractual counterparties to meet their obligations;

our ability to deliver required quantities of oil, gas, NGLs, or produced water to contractual counterparties;

price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;

the impact that depressed oil, gas, or NGL prices could have on our borrowing capacity under our Credit Agreement;

the possibility our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;

the possibility that covenants in our Credit Agreement or the indentures governing the Senior Notes and Senior Convertible Notes may limit our discretion in the operation of our business, prohibit us from engaging in beneficial transactions, or lead to the accelerated payment of our debt;

operating and environmental risks and hazards that could result in substantial losses;

the impact of extreme weather conditions on our ability to conduct drilling activities;

- our ability to acquire adequate supplies of water and dispose of or recycle water we use at a reasonable cost in accordance with environmental and other applicable rules;

complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;

the availability and capacity of gathering, transportation, processing, and/or refining facilities;

our ability to sell and/or receive market prices for our oil, gas, and NGLs;

new technologies may cause our current exploration and drilling methods to become obsolete;

the possibility of security threats, including terrorist attacks and cybersecurity breaches, against, or otherwise impacting, our facilities and systems; and

litigation, environmental matters, the potential impact of legislation and government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and actual results or performance may be materially different from those expressed or implied in the forward-looking statements. The forward-looking statements in this report speak as of the filing of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

### ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions Commodity Price Risk and Interest Rate Risk in Item 2 above, as well as under the section entitled Summary of Oil, Gas, and NGL Derivative Contracts in Place under Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report and is incorporated herein by reference. Please also refer to the information under Commodity Price Risk and Interest Rate Risk in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2017 Form 10-K.

#### ITEM 4. CONTROLS AND PROCEDURES

##### Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our Disclosure Controls are effective at a reasonable assurance level.

##### Changes in Internal Control Over Financial Reporting

There have been no changes during the first quarter of 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

**PART II. OTHER INFORMATION**

**ITEM 1. LEGAL PROCEEDINGS**

From time to time, we may be involved in litigation relating to claims arising out of our business and operations in the normal course of business. As of the filing of this report, no legal proceedings are pending against us that we believe individually or collectively are expected to have a materially adverse effect upon our financial condition, results of operations or cash flows.

**ITEM 1A. RISK FACTORS**

There have been no material changes to the risk factors as previously disclosed in our 2017 Form 10-K.

ITEM 6. EXHIBITS

The following exhibits are filed or furnished with or incorporated by reference into this report:

Exhibit Number	Description
<u>2.1</u>	<u>Purchase and Sale Agreement, dated January 8, 2018, by and between SM Energy Company and Converse Energy Acquisitions, LLC (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on January 11, 2018, and incorporated herein by reference)</u>
<u>3.1</u>	<u>Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)</u>
<u>3.2</u>	<u>Amended and Restated By-Laws of SM Energy Company, effective as of February 21, 2017 (filed as Exhibit 3.2 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2016, and incorporated herein by reference)</u>
<u>12.1*</u>	<u>Computation of Ratio of Earnings to Fixed Charges</u>
<u>31.1*</u>	<u>Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002</u>
<u>31.2*</u>	<u>Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002</u>
<u>32.1**</u>	<u>Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002</u>
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 Taxonomy Extension Definition Linkbase Document

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\* Filed with this report.

\*\* Furnished with this report.

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 hereunto duly authorized.

SM ENERGY COMPANY

May 4,  
By: /s/ JAVAN D. OTTOSON  
2018

Javan D. Ottoson  
President and Chief Executive Officer  
(Principal Executive Officer)

May 4,  
By: /s/ A. WADE PURSELL  
2018

A. Wade Pursell  
Executive Vice President and Chief Financial Officer  
(Principal Financial Officer)

May 4,  
By: /s/ MARK T. SOLOMON  
2018

Mark T. Solomon  
Vice President - Controller and Assistant Secretary  
(Principal Accounting Officer)