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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2018

or

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

For the transition period from ______ to ______

Commission file number: 1-13283

PENN VIRGINIA CORPORATION
(Exact name of registrant as specified in its charter)

Virginia	**23-1184320**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

14701 ST. MARY'S LANE, SUITE 275
HOUSTON, TX 77079
(Address of principal executive offices) (Zip Code)
(713) 722-6500
(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 ("Exchange Act") 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	☐	(Do not check if a smaller reporting company)	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 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 by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Exchange Act subsequent to the distribution of securities under a plan confirmed by a court. Yes ☒ No ☐

As of August 3, 2018, 15,058,480 shares of common stock of the registrant were outstanding.

PENN VIRGINIA CORPORATION
QUARTERLY REPORT ON FORM 10-Q

For the Quarterly Period Ended June 30, 2018

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Part I. FINANCIAL INFORMATION

Item 1. ***Financial Statements.***

PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS – unaudited
(in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues				
Crude oil	$ 101,716	$ 32,351	$ 172,974	$ 62,424
Natural gas liquids	5,533	2,043	8,479	4,345
Natural gas	3,912	1,880	6,702	4,223
Gain (loss) on sales of assets, net	4	(134)	79	(69)
Other revenues, net	415	142	557	345
Total revenues	111,580	36,282	188,791	71,268
Operating expenses				
Lease operating	8,730	5,370	16,026	10,286
Gathering, processing and transportation	4,574	2,555	7,933	5,106
Production and ad valorem taxes	5,795	2,119	9,887	4,098
General and administrative	5,322	3,702	11,793	7,809
Depreciation, depletion and amortization	31,273	11,076	53,354	20,886
Total operating expenses	55,694	24,822	98,993	48,185
Operating income	55,886	11,460	89,798	23,083
Other income (expense)				
Interest expense	(6,150)	(1,274)	(10,751)	(1,812)
Derivatives	(52,241)	11,061	(71,036)	28,077
Other, net	(16)	82	(74)	62
Income (loss) before income taxes	(2,521)	21,329	7,937	49,410
Income tax expense	—	—	(163)	—
Net income (loss)	$ (2,521)	$ 21,329	$ 7,774	$ 49,410
Net income (loss) per share:				
Basic	$ (0.17)	$ 1.42	$ 0.52	$ 3.30
Diluted	$ (0.17)	$ 1.42	$ 0.51	$ 3.27
Weighted average shares outstanding – basic	15,058	14,992	15,050	14,992
Weighted average shares outstanding – diluted	15,058	15,050	15,171	15,097

See accompanying notes to condensed consolidated financial statements.

PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME – unaudited
(in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net income (loss)	$ (2,521)	$ 21,329	$ 7,774	$ 49,410
Other comprehensive income:				
Change in pension and postretirement obligations, net of tax of $0 and $0 in 2018 and 2017, respectively	—	—	—	—
	—	—	—	—
Comprehensive income (loss)	$ (2,521)	$ 21,329	$ 7,774	$ 49,410

See accompanying notes to condensed consolidated financial statements.

PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS – unaudited
(in thousands, except share data)

	June 30, 2018	December 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$ 11,521	$ 11,017
Accounts receivable, net of allowance for doubtful accounts	71,572	69,821
Derivative assets	33	—
Other current assets	5,194	6,250
Total current assets	88,320	87,088
Property and equipment, net (full cost method)	791,624	529,059
Derivative assets	54	—
Deferred income taxes	4,780	4,943
Other assets	2,956	8,507
Total assets	$ 887,734	$ 629,597
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 127,982	$ 96,181
Derivative liabilities	63,257	27,777
Total current liabilities	191,239	123,958
Other liabilities	5,493	4,833
Derivative liabilities	29,566	13,900
Long-term debt, net	432,824	265,267
Commitments and contingencies (Note 13)		
Shareholders' equity:		
Preferred stock of $0.01 par value – 5,000,000 shares authorized; none issued	—	—
Common stock of $0.01 par value – 45,000,000 shares authorized; 15,058,480 and 15,018,870 shares issued as of June 30, 2018 and December 31, 2017, respectively	151	150
Paid-in capital	195,980	194,123
Retained earnings	32,481	27,366
Accumulated other comprehensive income	—	—
Total shareholders' equity	228,612	221,639
Total liabilities and shareholders' equity	$ 887,734	$ 629,597

See accompanying notes to condensed consolidated financial statements.

PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – unaudited
(in thousands)

	Six Months Ended June 30,	
	2018	**2017**
Cash flows from operating activities		
Net income	$ 7,774	$ 49,410
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	53,354	20,886
Derivative contracts:		
Net (gains) losses	71,036	(28,077)
Cash settlements, net	(19,977)	(2,458)
Deferred income tax expense	163	—
(Gain) loss on sales of assets, net	(79)	69
Non-cash interest expense	1,644	988
Share-based compensation (equity-classified)	2,451	1,694
Other, net	26	38
Changes in operating assets and liabilities, net	4,026	(6,533)
Net cash provided by operating activities	120,418	36,017
Cash flows from investing activities		
Acquisitions, net	(86,835)	—
Capital expenditures	(201,350)	(43,583)
Proceeds from sales of assets, net	2,525	—
Net cash used in investing activities	(285,660)	(43,583)
Cash flows from financing activities		
Proceeds from credit facility borrowings	166,500	14,000
Repayment of credit facility borrowings	—	(2,000)
Debt issuance costs paid	(754)	(1,090)
Proceeds received from rights offering, net	—	55
Other, net	—	(55)
Net cash provided by financing activities	165,746	10,910
Net increase in cash and cash equivalents	504	3,344
Cash and cash equivalents – beginning of period	11,017	6,761
Cash and cash equivalents – end of period	$ 11,521	$ 10,105
Supplemental disclosures:		
Cash paid for:		
Interest, net of amounts capitalized	$ 8,953	$ 795
Reorganization items, net	$ 442	$ 901
Non-cash investing and financing activities:		
Changes in accounts receivable related to acquisitions	$ (26,631)	$ —
Changes in other assets related to acquisitions	$ (2,469)	$ —
Changes in accrued liabilities related to acquisitions	$ (15,099)	$ —
Changes in accrued liabilities related to capital expenditures	$ 12,231	$ 2,322
Changes in other liabilities for asset retirement obligations related to acquisitions	$ 382	$ —

See accompanying notes to condensed consolidated financial statements.

1. Nature of Operations

Penn Virginia Corporation (together with its consolidated subsidiaries, unless the context otherwise requires, "Penn Virginia," the "Company," "we," "us" or "our") is an independent oil and gas company engaged in the onshore exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas. Our current operations consist primarily of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale (the "Eagle Ford") in Gonzales, Lavaca and DeWitt Counties in South Texas.

2. Basis of Presentation

Our unaudited Condensed Consolidated Financial Statements include the accounts of Penn Virginia and all of our subsidiaries. Intercompany balances and transactions have been eliminated. Our Condensed Consolidated Financial Statements have been prepared in conformity with accounting principles generally accepted in the United States of America ("GAAP"). Preparation of these statements involves the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals, considered necessary for a fair presentation of our Condensed Consolidated Financial Statements, have been included. Our Condensed Consolidated Financial Statements should be read in conjunction with the Consolidated Financial Statements and Notes included in our Annual Report on Form 10-K for the year ended December 31, 2017. Operating results for the six months ended June 30, 2018, are not necessarily indicative of the results that may be expected for the year ending December 31, 2018.

Reclassifications

We have reclassified certain amounts included within "Accounts payable and accrued liabilities" on our Condensed Consolidated Balance Sheet as of December 31, 2017, as disclosed in Note 11, in order to conform to the current period presentation.

Adoption of Recently Issued Accounting Pronouncements

Effective January 1, 2018, we adopted and began applying the relevant guidance provided in Accounting Standards Update ("ASU") 2017–07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* ("ASU 2017–07"). ASU 2017–07 requires employers to disaggregate the service cost component from the other components of net periodic benefit cost. The service cost component of net periodic benefit cost shall be reported in the same line item as other compensation costs arising from services rendered by the pertinent employees during the period, except for amounts capitalized. All other components of net periodic benefit cost shall be presented outside of a subtotal for income from operations. The line item used to present the components other than the service cost shall be disclosed if the other components are not presented in a separate line item or items. ASU 2017–07 is applicable to our legacy retiree benefit plans which cover a limited population of former employees. There is no service cost associated with these plans as they are not applicable to current employees, but rather there are interest and other costs associated with the legacy obligations. As required, ASU 2017–07 has been applied retrospectively to periods prior to 2018. Accordingly, the entirety of the expense associated with these plans, which was less than $0.1 million, has been included as a component of the "Other income (expense)" caption in our Condensed Consolidated Statement of Operations for each of the three and six months ended June 30, 2017. Prior to 2018, all costs associated with these plans were included in the "General and administrative" ("G&A") expenses caption.

Effective January 1, 2018, we adopted and began applying the relevant guidance provided in ASU 2014–09, *Revenues from Contracts with Customers* ("ASU 2014–09") and related amendments to GAAP which, together with ASU 2014–09, represent Accounting Standards Codification ("ASC") Topic 606, *Revenues from Contracts with Customers* ("ASC Topic 606"). We adopted ASC Topic 606 using the cumulative effect transition method (see Note 5 for the impact and disclosures associated with the adoption of ASC Topic 606.

Recently Issued Accounting Pronouncements Pending Adoption

In June 2016, the Financial Accounting Standards Board ("FASB") issued ASU 2016–13, *Measurement of Credit Losses on Financial Instruments* ("ASU 2016–13"), which changes the recognition model for the impairment of financial instruments, including accounts receivable, loans and held-to-maturity debt securities, among others. ASU 2016–13 is required to be adopted using the modified retrospective method by January 1, 2020, with early adoption permitted for fiscal periods beginning after December 15, 2018. In contrast to current guidance, which considers current information and events and utilizes a probable threshold, (an "incurred loss" model), ASU 2016–13 mandates an "expected loss" model. The expected loss model: (i) estimates the risk of loss even when risk is remote, (ii) estimates losses over the contractual life, (iii) considers past events, current conditions and reasonable supported forecasts and (iv) has no recognition threshold. ASU 2016–13 will have applicability to our accounts receivable portfolio, particularly those receivables attributable to our joint interest partners which have a higher credit risk than those associated with our traditional customer receivables. At this time, we do not anticipate that the adoption of ASU 2016–13 will have a significant impact on our Consolidated Financial Statements and related disclosures; however, we are continuing to evaluate the requirements and the period for which we will adopt the standard as well as monitoring developments regarding ASU 2016–13 that are unique to our industry.

In February 2016, the FASB issued ASU 2016–02, *Leases* ("ASU 2016–02"), which will require organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by those leases with terms of more than twelve months. Together with recent related amendments to GAAP, ASU 2016–02 represents ASC Topic 842, *Leases* ("ASC Topic 842") which supersedes all current GAAP with respect to leases. Consistent with current GAAP, the recognition, measurement and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. ASC Topic 842 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. The effective date of ASC Topic 842 is January 1, 2019, with early adoption permitted.

ASC Topic 842 will be applicable to our existing leases for office facilities and certain office equipment, vehicles and certain field equipment, land easements and similar arrangements for rights-of-way, and potentially to certain drilling rig and completion contracts with terms in excess of 12 months, to the extent we may have such contracts in the future. In addition, we believe that our crude oil and natural gas gathering commitment arrangements, as described in Note 13, include provisions that could be construed as leases. Our crude oil and natural gas gathering arrangements are fairly complex and include, among other provisions, multiple elements and term lengths, certain volumetric-based minimums and varying degrees of optionality available to both us and the service providers. Furthermore, these arrangements have certain material payment terms that are variable in nature which, depending upon the outcome of our analysis and resulting conclusions, could have a significant impact on the amounts recognized as right of use assets and corresponding lease liabilities. We anticipate that the adoption of ASC Topic 842 may significantly increase our total assets and liabilities. Accordingly, we are continuing to evaluate the effect that ASC Topic 842 will have on our Consolidated Financial Statements and related disclosures. We plan to adopt ASC Topic 842 on the effective date in 2019 using the optional transition method and will recognize a cumulative-effect adjustment to the opening balance of retained earnings. We are also continuing to monitor developments regarding ASC Topic 842 that are unique to our industry.

Going Concern Presumption

Our unaudited Condensed Consolidated Financial Statements have been prepared on a going concern basis, which contemplates the realization of assets and the satisfaction of liabilities and other commitments in the normal course of business.

Subsequent Events

Management has evaluated all of our activities through the issuance date of our Condensed Consolidated Financial Statements and has concluded that, with the exception of the divestiture of our Mid-Continent oil and gas properties as described in Note 3, no subsequent events have occurred that would require recognition in our Condensed Consolidated Financial Statements or disclosure in the Notes thereto.

3. Acquisitions and Divestitures

Acquisitions

Hunt Acquisition

In December 2017, we entered into a purchase and sale agreement with Hunt Oil Company ("Hunt") to acquire certain oil and gas assets in the Eagle Ford Shale, primarily in Gonzales County, Texas for $86.0 million in cash, subject to adjustments (the "Hunt Acquisition"). The Hunt Acquisition had an effective date of October 1, 2017, and closed on March 1, 2018, at which time we paid cash consideration of $84.4 million. In connection with the Hunt Acquisition, we also acquired working interests in certain wells that we previously drilled as operator in which Hunt had rights to participate prior to the transaction closing. Accumulated costs, net of suspended revenues for these wells was $13.8 million, which we have reflected as a component of the total net assets acquired. We funded the Hunt Acquisition with borrowings under our credit agreement (the "Credit Facility"). The Hunt Acquisition expanded our net leasehold position by approximately 9,700 net acres, substantially all of which is held by production, in the northwestern portion of our Eagle Ford acreage.

The final settlement of the Hunt Acquisition occurred in July 2018, at which time an additional $0.2 million of acquisition costs was allocated from certain working capital components and Hunt transferred $1.4 million to us primarily for suspended revenues attributable to the acquired properties.

We incurred a total of $0.5 million of transaction costs for legal, due diligence and other professional fees associated with the Hunt Acquisition, including $0.1 million in 2017 and $0.4 million in the first quarter of 2018. These costs have been recognized as a component of our G&A expenses.

We accounted for the Hunt Acquisition by applying the acquisition method of accounting as of March 1, 2018. The following table represents the final fair values assigned to the net assets acquired and the total acquisition cost incurred, including consideration transferred to Hunt:

Assets		
Oil and gas properties - proved	$	82,443
Oil and gas properties - unproved		16,339
Liabilities		
Asset retirement obligations		356
Net assets acquired	$	98,426
Cash consideration paid to Hunt	$	84,403
Application of working capital adjustments		245
Accumulated costs, net of suspended revenues, for wells in which Hunt had rights to participate		13,778
Total acquisition costs incurred	$	98,426

Devon Acquisition

In July 2017, we entered into a purchase and sale agreement (the "Purchase Agreement") with Devon Energy Corporation ("Devon") to acquire all of Devon's right, title and interest in and to certain oil and gas assets (the "Devon Properties"), including oil and gas leases covering approximately 19,600 net acres located primarily in Lavaca County, Texas for aggregate consideration of $205 million in cash (the "Devon Acquisition"). Upon execution of the Purchase Agreement, we deposited $10.3 million as earnest money into an escrow account (the "Escrow Account"). The Devon Acquisition had an effective date of March 1, 2017, and closed on September 29, 2017, at which time we paid cash consideration of $189.9 million and $7.1 million was released from the Escrow Account to Devon. In November 2017, we acquired additional working interests in the Devon Properties for $0.7 million from parties that had tag-along rights to sell their interests under the Purchase Agreement.

As of December 31, 2017, $3.2 million remained in the Escrow Account, which was included as a component of noncurrent "Other assets" on our Condensed Consolidated Balance Sheet. The final settlements of the Devon Acquisition together with the tag-along rights acquisition, occurred in February 2018, at which time $2.5 million in cash was transferred from the Escrow Account to Devon, and the remaining $0.7 million was distributed to us. In addition, Devon transferred $0.4 million to us for suspended revenues attributable to the acquired properties.

The Devon Acquisition was financed with the net proceeds received from borrowings under the $200 million Second Lien Credit Agreement dated as of September 29, 2017 (the "Second Lien Facility") (see Note 8 for terms of the Second Lien Facility) and incremental borrowings under the Credit Facility.

We incurred a total of $1.0 million of transaction costs in 2017 associated with the Devon Acquisition, including advisory, legal, due diligence and other professional fees. These costs have been recognized as a component of our G&A expenses.

We accounted for the Devon Acquisition by applying the acquisition method of accounting as of September 29, 2017. The following table represents the final fair values assigned to the net assets acquired and the total consideration transferred:

Assets		
Oil and gas properties - proved	$	42,866
Oil and gas properties - unproved		146,686
Other property and equipment		8,642
Liabilities		
Revenue suspense		355
Asset retirement obligations		494
Net assets acquired	$	197,345
Cash consideration paid to Devon and tag-along parties, net	$	190,277
Amount transferred to Devon from the Escrow Account		9,519
Application of working capital adjustments, net		(2,451)
Total consideration transferred	$	197,345

Valuation of Acquisitions

The fair values of the oil and gas properties acquired in the Hunt and Devon Acquisitions were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) future cash flows, (v) the timing of our development plans and (vi) a market-based weighted-average cost of capital. The fair value of the other property and equipment acquired was measured primarily with reference to replacement costs for similar assets adjusted for the age and normal use of the underlying assets. Because many of these inputs are not observable, we have classified the initial fair value estimates as Level 3 inputs as that term is defined in GAAP.

Impact of Acquisitions on Actual and Pro Forma Results of Operations

The results of operations attributable to the Hunt Acquisition and Devon Acquisition have been included in our Consolidated Financial Statements for the periods after March 1, 2018 and after September 29, 2017, respectively. The Hunt Acquisition provided revenues and estimated earnings (including revenues less operating expenses and excluding allocations of interest expense and income taxes) of approximately $0.4 million and $0.2 million, respectively, for the period from March 1, 2018 through March 31, 2018. As the properties and working interests acquired in connection with the Hunt and Devon Acquisitions are included within our existing Eagle Ford acreage, it is not practical or meaningful to disclose revenues and earnings unique to those assets for periods beyond those during which they were acquired, as they were fully integrated into our regional operations soon after their acquisition. The following table presents unaudited summary pro forma financial information for the three and six months ended June 30, 2018 and 2017, assuming the Hunt and Devon Acquisitions and the related entry into the Second Lien Facility occurred as of January 1, 2017. The pro forma financial information does not purport to represent what our actual results of operations would have been if the Hunt and Devon Acquisitions and the entry into the Second Lien Facility had occurred as of this date, or the results of operations for any future periods.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Total revenues	$ 111,580	$ 51,978	$ 194,036	$ 99,699
Net income (loss)	$ (2,521)	$ 22,651	$ 10,868	$ 50,839
Net income (loss) per share - basic	$ (0.17)	$ 1.51	$ 0.72	$ 3.39
Net income (loss) per share - diluted	$ (0.17)	$ 1.51	$ 0.72	$ 3.37

***Divestiture*s**

Mid-Continent Divestiture

In June 2018, we entered into a purchase and sale agreement with a third party to sell all of our remaining Mid-Continent oil and gas properties, located primarily in Oklahoma in the Granite Wash, for $6.0 million in cash, subject to customary adjustments. Upon the signing of the purchase and sale agreement, the buyer paid us a deposit in the amount of $0.7 million. The deposit has been reflected as a component of "Accounts payable and accrued liabilities" on our Condensed Consolidated Balance Sheet. The sale has an effective date of March 1, 2018 and closed on July 31, 2018, at which time we received proceeds of $5.5 million. The sale proceeds and de-recognition of certain assets and liabilities will be recorded as a reduction of our net oil and gas properties. A final settlement is scheduled to occur in the fourth quarter of 2018.

The properties have asset retirement obligations ("AROs") of $0.3 million. We also had a net working capital deficit attributable to the oil and gas properties of $1.1 million as of June 30, 2018. The net pre-tax operating income attributable to the Mid-Continent assets was $0.6 million and $0.3 million for the three months ended June 30, 2018 and 2017, and $1.4 million and $0.6 million for the six months ended June 30, 2018 and 2017, respectively.

Sales of Undeveloped Acreage, Rights and Other Assets

In February 2018, we sold our undeveloped acreage holdings in the Tuscaloosa Marine Shale in Louisiana that were scheduled to expire in 2019. In March 2018, we sold certain undeveloped deep leasehold rights in Oklahoma, and in May 2018, we sold certain pipeline assets in our former Marcellus Shale operating region. We received a combined total of $1.7 million for these leasehold and other assets which were applied as a reduction of our net oil and gas properties.

4. Bankruptcy Proceedings and Emergence

On May 12, 2016, we and eight of our subsidiaries filed voluntary petitions (*In re Penn Virginia Corporation, et al., Case No. 16-32395*) seeking relief under Chapter 11 of Title 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Eastern District of Virginia (the "Bankruptcy Court").

On August 11, 2016, the Bankruptcy Court confirmed our Second Amended Joint Chapter 11 Plan of Reorganization of Penn Virginia Corporation and its Debtor Affiliates, and we subsequently emerged from bankruptcy on September 12, 2016 (the "Emergence Date").

Effective January 17, 2018, the Bankruptcy Court closed the eight cases attributable to our subsidiaries, leaving the aforementioned lead case open pending the entry of a final decree or order by the Bankruptcy Court. While our emergence from bankruptcy is effectively complete, certain administrative and claims resolution activities will continue under the authority of the Bankruptcy Court until they have been appropriately discharged. As of August 3, 2018, certain claims were still in the process of resolution. While most of these matters are unsecured claims for which shares of our common stock have been allocated, certain of these matters must be settled with cash payments. As of June 30, 2018, we had $3.9 million reserved for outstanding claims to be potentially settled in cash. This reserve is included as a component of "Accounts payable and accrued liabilities" on our Condensed Consolidated Balance Sheet.

5. Accounts Receivable and Revenues from Contracts with Customers

Accounts Receivable and Major Customers

The following table summarizes our accounts receivable by type as of the dates presented:

	June 30, 2018	December 31, 2017
Customers	$ 55,736	$ 39,106
Joint interest partners	17,834	32,493
Other	364	584
	73,934	72,183
Less: Allowance for doubtful accounts	(2,362)	(2,362)
	$ 71,572	$ 69,821

For the six months ended June 30, 2018, three customers accounted for $157.8 million, or approximately 84%, of our consolidated product revenues. The revenues generated from these customers during the six months ended June 30, 2018, were $81.0 million, $41.0 million and $35.8 million, or 43%, 22% and 19% of the consolidated total, respectively. As of June 30, 2018 and December 31, 2017, $41.9 million and $32.1 million, or approximately 75% and 82%, of our consolidated accounts receivable from customers was related to these customers. No significant uncertainties exist related to the collectability of amounts owed to us by any of these customers. For the six months ended June 30, 2017, one customer accounted for $64.6 million, or approximately 91%, of our consolidated product revenues.

Revenue from Contracts with Customers

Adoption of ASC Topic 606

Effective January 1, 2018, we adopted ASC Topic 606 and have applied the guidance therein to our contacts with customers for the sale of commodity products (crude oil, NGLs and natural gas) as well as marketing services that we provide to our joint venture partners and other third parties. ASC Topic 606 provides for a five-step revenue recognition process model to determine the transfer of goods or services to consumers in an amount that reflects the consideration to which we expect to be entitled in exchange for such goods and services.

Upon the adoption of ASC Topic 606, we: (i) changed the presentation of our NGL product revenues from a gross basis to a net basis and changed the classification of certain natural gas processing costs associated with NGLs from a component of "Gathering, processing and transportation" ("GPT") expense to a reduction of NGL product revenues as described in further detail below, (ii) wrote off $2.7 million of accounts receivable arising from natural gas imbalances accounted for under the entitlements method as a direct reduction to our beginning balance of retained earnings as of January 1, 2018, and (iii) adopted the sales method with respect to production imbalance transactions beginning after December 31, 2017.

The following table illustrates the impact of the adoption of ASC Topic 606 on our Condensed Consolidated Statement of Operations for the three and six months ended June 30, 2018:

	Three Months Ended June 30, 2018		
	As Determined Under Prior GAAP	**As Reported Under ASC Topic 606**	**Increase (Decrease)**
Revenues			
Crude oil	$ 101,716	$ 101,716	$ —
Natural gas liquids	$ 6,103	$ 5,533	$ (570)
Natural gas	$ 3,912	$ 3,912	$ —
Marketing services (included in Other revenues, net)	$ 153	$ 153	$ —
Operating expenses			
Gathering, processing and transportation	$ 5,144	$ 4,574	$ (570)
Net loss	$ (2,521)	$ (2,521)	$ —

	Six Months Ended June 30, 2018		
	As Determined Under Prior GAAP	**As Reported Under ASC Topic 606**	**Increase (Decrease)**
Revenues			
Crude oil	$ 172,974	$ 172,974	$ —
Natural gas liquids	$ 9,495	$ 8,479	$ (1,016)
Natural gas	$ 6,702	$ 6,702	$ —
Marketing services (included in Other revenues, net)	$ 245	$ 245	$ —
Operating expenses			
Gathering, processing and transportation	$ 8,949	$ 7,933	$ (1,016)
Net income	$ 7,774	$ 7,774	$ —

Accounting Policies for Revenue Recognition and Associated Costs

Crude oil. We sell our crude oil production to our customers at either the wellhead or a contractually agreed-upon delivery point, including certain regional central delivery point terminals or pipeline inter-connections. We recognize revenue when control transfers to the customer considering factors associated with custody, title, risk of loss and other contractual provisions as appropriate. Pricing is based on a market index with adjustments for product quality, location differentials and, if applicable, deductions for intermediate transportation. Costs incurred by us for gathering and transporting the products to an agreed-upon delivery point are recognized as a component of GPT expense.

NGLs. We have natural gas processing contracts in place with certain midstream processing vendors. We deliver “wet” natural gas to our midstream processing vendors at the inlet of their processing facilities through gathering lines, certain of which we own and others which are owned by gathering service providers. Subsequent to processing, NGLs are delivered or otherwise transported to a third-party customer. Depending upon the nature of the contractual arrangements with the midstream processing vendors, particularly those attributable to the marketing of the NGL products, we recognize revenue for NGL products on either a gross or net basis. For those contracts where we have determined that we are the principal, and the ultimate third party is our customer, we recognize revenue on a gross basis, with associated processing costs presented as GPT expenses. For those contracts where we have determined that we are the agent and the midstream processing vendor is our customer, we recognize NGL product revenues based on a net basis with processing costs presented as a reduction of revenue. Based on an analysis of all of our existing natural gas processing contracts, we have determined that, as of January 1, 2018, and through June 30, 2018, we are the agent and our midstream processing vendors are our customers with respect to all of our NGL product sales.

Natural gas. Subsequent to the aforementioned processing of “wet” natural gas and the separation of NGL products, the “dry” or residue gas is delivered to us at the tailgate of the midstream processing vendors’ facilities and we market the product to our customers, most of whom are interstate pipelines. We recognize revenue when control transfers to the customer considering factors associated with custody, title, risk of loss and other contractual provisions as appropriate. Pricing is based on a market index with adjustments for product quality and location differentials, as applicable. Costs incurred by us for gathering and transportation from the wellhead through the processing facilities are recognized as a component of GPT expenses.

Marketing services. We provide marketing services to certain of our joint venture partners and other third parties with respect to oil and gas production for which we are the operator. Pricing for such services represents a negotiated fixed rate fee based on the sales price of the underlying oil and gas products. Production attributable to joint venture partners from wells that we operate that are not subject to marketing agreements are delivered in kind. Marketing revenue is recognized simultaneously with the sale of our commodity production to our customers. Direct costs associated with our marketing efforts are included in G&A expenses.

Transaction Prices, Contract Balances and Performance Obligations

Substantially all of our commodity product sales are short-term in nature with contract terms of one year or less. Accordingly, we have applied the practical expedient included in ASC Topic 606, which provides for an exemption from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Under our commodity product sales contracts, we bill our customers and recognize revenue when our performance obligations have been satisfied as described above. At that time, we have determined that payment is unconditional. Accordingly, our commodity sales contracts do not create contract assets or liabilities as those terms are defined in ASC Topic 606.

We record revenue in the month that our oil and gas production is delivered to our customers. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production, particularly from properties that are operated by our joint venture partners. We record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

6. Derivative Instruments

We utilize derivative instruments to mitigate our financial exposure to commodity price volatility. Our derivative instruments are not formally designated as hedges in the context of GAAP.

We typically utilize collars and swaps, which are placed with financial institutions that we believe to be acceptable credit risks, to hedge against the variability in cash flows associated with anticipated sales of our future production. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues from favorable price movements.

The counterparty to a collar or swap contract is required to make a payment to us if the settlement price for any settlement period is below the floor or swap price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling or swap price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract.

We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for West Texas Intermediate ("WTI") crude oil and Louisiana Light Sweet ("LLS") closing prices as of the end of the reporting period. The discounted cash flows utilize discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position, and our own credit risk if the derivative is in a liability position. We are currently unhedged with respect to NGL and natural gas production.

The following table sets forth our commodity derivative positions, presented on a net basis by period of maturity, as of June 30, 2018:

	Instrument	Average Volume Per Day	Weighted Average Price	Fair Value Asset	Fair Value Liability
Crude Oil:		(barrels)	($/barrel)		
Third quarter 2018	Swaps-WTI	10,455	$ 57.05	$ —	$ 14,270
Third quarter 2018	Swaps-LLS	6,000	$ 65.27	—	5,605
Fourth quarter 2018	Swaps-WTI	10,455	$ 57.05	—	11,332
Fourth quarter 2018	Swaps-LLS	6,000	$ 65.27	—	4,418
First quarter 2019	Swaps-WTI	6,446	$ 54.46	—	6,999
First quarter 2019	Swaps-LLS	5,000	$ 59.17	—	5,310
Second quarter 2019	Swaps-WTI	6,421	$ 54.48	—	6,115
Second quarter 2019	Swaps-LLS	5,000	$ 59.17	—	4,568
Third quarter 2019	Swaps-WTI	6,397	$ 54.50	—	5,337
Third quarter 2019	Swaps-LLS	5,000	$ 59.17	—	3,876
Fourth quarter 2019	Swaps-WTI	6,398	$ 54.50	—	4,635
Fourth quarter 2019	Swaps-LLS	5,000	$ 59.17	—	3,221
First quarter 2020	Swaps-WTI	6,000	$ 54.09	—	3,846
Second quarter 2020	Swaps-WTI	6,000	$ 54.09	—	3,302
Third quarter 2020	Swaps-WTI	6,000	$ 54.09	—	2,844
Fourth quarter 2020	Swaps-WTI	6,000	$ 54.09	—	2,451
Settlements to be paid in subsequent period					4,607

Financial Statement Impact of Derivatives

The impact of our derivative activities on income is included in “Derivatives” in our Condensed Consolidated Statements of Operations. The following table summarizes the effects of our derivative activities for the periods presented:

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Derivative gains (losses)	$ (52,241)	$ 11,061	$ (71,036)	$ 28,077

The effects of derivative gains and (losses) and cash settlements are reported as adjustments to reconcile net income to net cash provided by operating activities. These items are recorded in the “Derivative contracts” section of our Condensed Consolidated Statements of Cash Flows under “Net (gains) losses” and “Cash settlements, net.”

The following table summarizes the fair values of our derivative instruments presented on a gross basis, as well as the locations of these instruments on our Condensed Consolidated Balance Sheets as of the dates presented:

Type	Balance Sheet Location	June 30, 2018 Derivative Assets	June 30, 2018 Derivative Liabilities	December 31, 2017 Derivative Assets	December 31, 2017 Derivative Liabilities
Commodity contracts	Derivative assets/liabilities – current	$ 33	$ 63,257	$ —	$ 27,777
Commodity contracts	Derivative assets/liabilities – noncurrent	54	29,566	—	13,900
		$ 87	$ 92,823	$ —	$ 41,677

As of June 30, 2018, we reported net commodity derivative liabilities of $92.7 million. The contracts associated with this position are with eight counterparties, all of which are investment grade financial institutions. This concentration may impact our overall credit risk in that these counterparties may be similarly affected by changes in economic or other conditions. We have neither paid to, nor received from, our counterparties any cash collateral in connection with our derivative positions. Furthermore, our derivative contracts are not subject to margin calls or similar accelerations. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

7. Property and Equipment

The following table summarizes our property and equipment as of the dates presented:

	June 30, 2018	December 31, 2017
Oil and gas properties:		
Proved	$ 756,863	$ 460,029
Unproved	134,943	117,634
Total oil and gas properties	891,806	577,663
Other property and equipment	16,105	12,712
Total properties and equipment	907,911	590,375
Accumulated depreciation, depletion and amortization	(116,287)	(61,316)
	$ 791,624	$ 529,059

Unproved property costs of $134.9 million and $117.6 million have been excluded from amortization as of June 30, 2018 and December 31, 2017, respectively. We transferred $5.6 million of undeveloped leasehold costs associated with acreage unlikely to be drilled or associated with proved undeveloped reserves, including capitalized interest, from unproved properties to the full cost pool during the six months ended June 30, 2018. We capitalized internal costs of $1.6 million and $1.1 million and interest of $4.7 million and less than $0.1 million during the six months ended June 30, 2018 and 2017, respectively, in accordance with our accounting policies. Average depreciation, depletion and amortization ("DD&A") per barrel of oil equivalent of proved oil and gas properties was $15.36 and $11.74 for the six months ended June 30, 2018 and 2017, respectively.

8. Long-Term Debt

The following table summarizes our debt obligations as of the dates presented:

	June 30, 2018		December 31, 2017	
	Principal	Unamortized Discount and Deferred Issuance Costs [1, 2]	Principal	Unamortized Discount and Deferred Issuance Costs [1, 2]
Credit facility	$ 243,500		$ 77,000	
Second lien term loan	200,000	$ 10,676	200,000	$ 11,733
Totals	443,500	$ 10,676	277,000	$ 11,733
Less: Unamortized discount	(3,506)		(3,839)	
Less: Unamortized deferred issuance costs	(7,170)		(7,894)	
Long-term debt, net	$ 432,824		$ 265,267	

[1] Issuance costs of the Credit Facility, which represent costs attributable to the access to credit over its contractual term, have been presented as a component of Other assets (see Note 11) and are being amortized over the term of the Credit Facility using the straight-line method.

[2] Discount and issuance costs of the Second Lien Facility are being amortized over the term of the underlying loan using the effective-interest method

Credit Facility

On the Emergence Date, we entered into the Credit Facility. The Credit Facility provides for a $340.0 million revolving commitment and borrowing base and a $5 million sublimit for the issuance of letters of credit. In March 2018, the borrowing base under the Credit Facility was redetermined from $237.5 million to $340.0 million pursuant to the Master Assignment, Agreement and Amendment No. 4 to the Credit Facility (the "Fourth Amendment"). In the six months ended June 30, 2018, we paid and capitalized issue costs of $0.7 million in connection with the Fourth Amendment. The availability under the Credit Facility may not exceed the lesser of the aggregate commitments or the borrowing base. The borrowing base under the Credit Facility is redetermined generally semi-annually in April and October of each year. Additionally, the Credit Facility lenders may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The April 2018 redetermination was accelerated to March in connection with the Hunt Acquisition. The Credit Facility is available to us for general corporate purposes, including working capital. The Credit Facility matures in September 2020. We had $0.8 million in letters of credit outstanding as of June 30, 2018 and December 31, 2017.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 2.00% to 3.00%, determined based on the average availability under the Credit Facility or (b) a customary London interbank offered rate ("LIBOR") plus an applicable margin ranging from 3.00% to 4.00%, determined based on the average availability under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on LIBOR borrowings is payable every one, three or six months, at our election, and is computed on the basis of a year of 360 days. As of June 30, 2018, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 5.58%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility is guaranteed by us and all of our subsidiaries (the "Guarantor Subsidiaries"). The guarantees under the Credit Facility are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. There are no significant restrictions on our ability or any of the Guarantor Subsidiaries to obtain funds through dividends, advances or loans. The obligations under the Credit Facility are secured by a first priority lien on substantially all of our assets.

The Credit Facility requires us to maintain (1) a minimum interest coverage ratio (adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses as defined in the Credit Facility ("EBITDAX") to adjusted interest expense), measured as of the last day of each fiscal quarter, of 3.00 to 1.00, (2) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset), measured as of the last day of each fiscal quarter of 1.00 to 1.00, and (3) a maximum leverage ratio (consolidated indebtedness to EBITDAX), measured as of the last day of each fiscal quarter of 3.50 to 1.00.

The Credit Facility also contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports and budgets, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens and indebtedness, merger, consolidation or sale of assets, payment of dividends, and transactions with affiliates and other customary covenants.

The Credit Facility contains customary events of default and remedies for credit facilities of this nature. If we do not comply with the financial and other covenants in the Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility.

As of June 30, 2018, and through the date upon which the Condensed Consolidated Financial Statements were issued, we were in compliance with all of the covenants under the Credit Facility.

Second Lien Facility

On September 29, 2017, we entered into the $200 million Second Lien Facility. We received net proceeds of $187.8 million from the Second Lien Facility net of an original issue discount ("OID") of $4.0 million and issue costs of $8.2 million. The proceeds from the Second Lien Facility were used to fund the Devon Acquisition and related fees and expenses. The maturity date under the Second Lien Facility is September 29, 2022.

The outstanding borrowings under the Second Lien Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate based on the prime rate plus an applicable margin of 6.00% or (b) a customary LIBOR rate plus an applicable margin of 7.00%. As of June 30, 2018, the actual interest rate of outstanding borrowings under the Second Lien Facility was 9.10%. Amounts under the Second Lien Facility were borrowed at a price of 98% with an initial interest rate of 8.34%, resulting in an effective interest rate of 9.89%. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on eurocurrency borrowings is payable every one or three months (including in three-month intervals if we select a six-month interest period), at our election and is computed on the basis of a 360-day year. We have the right, to the extent permitted under the Credit Facility and an intercreditor agreement between the lenders under the Credit Facility and the lenders under the Second Lien Facility, to prepay loans under the Second Lien Facility at any time, subject to the following prepayment premiums (in addition to customary "breakage" costs with respect to eurocurrency loans): during year one, a customary "make-whole" premium; during year two, 102% of the amount being prepaid; during year three, 101% of the amount being prepaid; and thereafter, no premium. The Second Lien Facility also provides for the following prepayment premiums in the event of a change in control that results in an offer of prepayment that is accepted by the lenders under the Second Lien Facility: during years one and two, 102% of the amount being prepaid; during year three, 101% of the amount being prepaid; and thereafter, no premium.

The Second Lien Facility is collateralized by substantially all of the Company's and its subsidiaries' assets with lien priority subordinated to the liens securing the Credit Facility. The obligations under the Second Lien Facility are guaranteed by us and the Guarantor Subsidiaries.

The Second Lien Facility has no financial covenants, but contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports and budgets, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens and indebtedness, merger, consolidation or sale of assets and transactions with affiliates and other customary covenants.

As illustrated in the table above, the OID and issue costs of the Second Lien Facility are presented as reductions to the outstanding term loans. These costs are subject to amortization using the interest method over the five-year term of the Second Lien Facility.

As of June 30, 2018, and through the date upon which the Consolidated Financial Statements were issued, we were in compliance with all of the covenants under the Second Lien Facility.

9. Income Taxes

On December 22, 2017, the U.S. Congress enacted comprehensive tax legislation as part of the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act (the “TCJA”). The TCJA makes broad and complex changes to the U.S. tax code, including but not limited to, (i) reducing the U.S. federal corporate income tax rate from 35% to 21%; (ii) allowing the immediate deduction of certain new investments in lieu of depreciation expense over time; (iii) creating a new limitation on deductible interest expense; (iv) changing rules related to use and limitations of net operating loss (“NOL”) carryforwards created in tax years beginning after December 31, 2017, and (v) repeal of the corporate alternative minimum tax (“AMT”).

In connection with our initial analysis of the impact of the TCJA, our Condensed Consolidated Balance Sheet as of December 31, 2017 included a deferred tax asset of $4.9 million attributable to our AMT credit carryforwards that were previously fully reserved, but became realizable in connection with the AMT provisions of the TCJA. We continue to analyze the impacts of the TCJA on the Company and refine our estimates during 2018.

We recognized a federal and state income tax expense for the six months ended June 30, 2018 at the blended rate of 21.6%; however, the federal and state tax expense was offset by an adjustment to the valuation allowance against our net deferred tax assets along with an adjustment of $0.2 million to the deferred tax asset related to sequestration of a portion of the aforementioned AMT credit carryforward resulting in an effective tax rate of 2.1%. The effect of the adjustment was to reduce our deferred tax asset to $4.8 million as of June 30, 2018. We recognized a federal income tax benefit for the six months ended June 30, 2017 at the blended rate of 35.2% which was fully offset by a valuation allowance against our net deferred tax assets. We considered both the positive and negative evidence in determining that it was more likely than not that some portion or all of our deferred tax assets will not be realized, primarily as a result of cumulative losses.

We had no liability for unrecognized tax benefits as of June 30, 2018. There were no interest and penalty charges recognized during the periods ended June 30, 2018 and 2017. Tax years from 2013 forward remain open for examination by the Internal Revenue Service and various state jurisdictions.

10. Executive Retirement

Effective February 28, 2018, Mr. Harry Quarls retired from his position as a director and Executive Chairman of the Company. In connection with his retirement, we entered into a separation and consulting agreement (“Separation Agreement”) whereby Mr. Quarls will provide transition and support services to us through December 31, 2018. We paid Mr. Quarls $0.3 million for such services and a mutually agreed-upon amount for any services in excess of a minimum level established in the Separation Agreement. The Separation Agreement included a general release of claims and provided for the accelerated vesting of certain share-based compensation awards for which we recognized expense of $0.6 million during the six months ended June 30, 2018 (see Note 15). The costs associated with the Separation Agreement, including the share-based compensation charges, are included as a component of G&A expenses in our Condensed Consolidated Statements of Operation.

11. Additional Balance Sheet Detail

The following table summarizes components of selected balance sheet accounts as of the dates presented:

	June 30, 2018	December 31, 2017
Other current assets:		
Tubular inventory and well materials	$ 3,817	$ 5,146
Prepaid expenses	1,377	1,104
	$ 5,194	$ 6,250
Other assets:		
Deferred issuance costs of the Credit Facility	$ 2,923	$ 2,857
Deposit in escrow [1]	—	3,210
Other	33	2,440
	$ 2,956	$ 8,507
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 34,582	$ 22,579
Drilling costs	34,620	22,389
Royalties and revenue – related	43,862	39,287
Production, ad valorem and other taxes [2]	3,827	1,275
Compensation – related	2,802	2,975
Interest	377	223
Reserve for bankruptcy claims	3,940	3,933
Deposit received for divestiture of Mid-Continent properties [3]	700	—
Other [2]	3,272	3,520
	$ 127,982	$ 96,181
Other liabilities:		
Asset retirement obligations	$ 3,987	$ 3,286
Defined benefit pension obligations	897	971
Postretirement health care benefit obligations	509	476
Other	100	100
	$ 5,493	$ 4,833

[1] Represents the amount remaining in the Escrow Account for the Devon Acquisition, which was utilized to fund the remaining liabilities due to Devon for the final settlement in March 2018 (see Note 3).
[2] The amount for December 31, 2017 was reclassified from Accounts payable and accrued expenses - Other.
[3] Represents the deposit paid to us related to the Mid-Continent divestiture (see Note 3).

12. Fair Value Measurements

We apply the authoritative accounting provisions included in GAAP for measuring the fair value of both our financial and nonfinancial assets and liabilities. Fair value is an exit price representing the expected amount we would receive upon the sale of an asset or that we would expect to pay to transfer a liability in an orderly transaction with market participants at the measurement date.

Our financial instruments that are subject to fair value disclosure consist of cash and cash equivalents, accounts receivable, accounts payable, derivatives and our Credit Facility and Second Lien Facility borrowings. As of June 30, 2018, the carrying values of all of these financial instruments approximated fair value.

Recurring Fair Value Measurements

Certain financial assets and liabilities are measured at fair value on a recurring basis on our Condensed Consolidated Balance Sheets. The following tables summarize the valuation of those assets and (liabilities) as of the dates presented:

	June 30, 2018			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Assets:				
Commodity derivative assets – current	$ 33	$ —	$ 33	$ —
Commodity derivative assets – noncurrent	$ 54	$ —	$ 54	$ —
Liabilities:				
Commodity derivative liabilities – current	$ (63,257)	$ —	$ (63,257)	$ —
Commodity derivative liabilities – noncurrent	$ (29,566)	$ —	$ (29,566)	$ —

	December 31, 2017			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Liabilities:				
Commodity derivative liabilities – current	$ (27,777)	$ —	$ (27,777)	$ —
Commodity derivative liabilities – noncurrent	$ (13,900)	$ —	$ (13,900)	$ —

Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one level of the fair value hierarchy to another level. In such instances, the transfer is deemed to have occurred at the beginning of the quarterly period in which the event or change in circumstances that caused the transfer occurred. There were no transfers during the six months ended June 30, 2018 and 2017.

We used the following methods and assumptions to estimate fair values for the financial assets and liabilities described below:

- *Commodity derivatives*: We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for WTI and LLS crude oil closing prices as of the end of the reporting periods. We generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. Each of these is a Level 2 input.

Non-Recurring Fair Value Measurements

In addition to the fair value measurements applied with respect to the Hunt and Devon Acquisitions, as described in Note 3, the most significant non-recurring fair value measurements utilized in the preparation of our Condensed Consolidated Financial Statements are those attributable to the initial determination of AROs associated with the ongoing development of new oil and gas properties. The determination of the fair value of AROs is based upon regional market and facility specific information. The amount of an ARO and the costs capitalized represent the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using a rate commensurate with the risk, which approximates our cost of funds. Because these significant fair value inputs are typically not observable, we have categorized the initial estimates as Level 3 inputs.

13. Commitments and Contingencies

Gathering and Intermediate Transportation Commitments

We have long-term agreements with Republic Midstream, LLC ("Republic Midstream") and Republic Midstream Marketing, LLC ("Republic Marketing" and, together with Republic Midstream, collectively, "Republic") to provide gathering and intermediate pipeline transportation services for a substantial portion of our crude oil and condensate production in the South Texas region as well as volume capacity support for certain downstream interstate pipeline transportation.

Republic is obligated to gather and transport our crude oil and condensate from within a dedicated area in the Eagle Ford via a gathering system and intermediate takeaway pipeline connecting to a downstream interstate pipeline operated by a third party through 2041. We have a minimum volume commitment ("MVC") of 8,000 gross barrels of oil per day to Republic through 2031 under the gathering agreement.

Under the marketing agreement, we have a 10-year commitment to sell 8,000 barrels per day of crude oil (gross) to Republic, or to any third party, utilizing Republic Marketing's capacity on a certain downstream interstate pipeline.

Excluding the potential impact of the effects of price escalation from commodity price changes, the minimum fee requirements attributable to the MVC under the gathering and transportation agreement are as follows: $5.3 million for the remainder of 2018, $11.7 million for 2019, $13.0 million per year for 2020 through 2025, $7.4 million for 2026, $3.8 million per year for 2027 through 2030 and $2.2 million for 2031.

Drilling, Completion and Other Commitments

We have contractual commitments for three drilling rigs as of June 30, 2018 with terms expiring in August 2018, September 2018 and November 2018, respectively. We also have one-year purchase commitments for the utilization of certain frac services and the purchase of certain materials for completion operations. Both the frac services and materials commitments were effective January 1, 2018. We have approximately $22.6 million of combined obligations associated with these commitments. In May 2018, we committed to a five-year lease for new corporate office facilities that will begin in August 2018. The minimum lease commitments are as follows: less than $0.1 million for 2018, $0.4 million for 2019, $0.6 million for 2020, $0.6 million for 2021, $0.6 million for 2022 and $0.6 million for 2023.

Legal and Regulatory

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes that these claims will not have a material effect on our financial position, results of operations or cash flows. As of June 30, 2018, we continue to maintain a $0.1 million reserve for a litigation matter. As of June 30, 2018, we also had AROs of approximately $4.0 million attributable to the plugging of abandoned wells.

14. Shareholders' Equity

The following tables summarize the components of our shareholders ' equity and the changes therein as of and for the six months ended June 30, 2018:

	December 31, 2017	Net Income	All Other Changes [1]	June 30, 2018
Common stock	$ 150	$ —	$ 1	$ 151
Paid-in capital	194,123	—	1,857	195,980
Retained earnings	27,366	7,774	(2,659)	32,481
Accumulated other comprehensive income	—	—	—	—
	$ 221,639	$ 7,774	$ (801)	$ 228,612

[1] Includes equity-classified share-based compensation of $2.5 million during the six months ended June 30, 2018 . During the six months ended June 30, 2018 , 38,115 and 1,495 shares of common stock were issued in connection with the vesting of certain time-vested restricted stock units ("RSUs") and performance restricted stock units ("PRSUs"), net of shares withheld for income taxes, respectively. This also includes a write-off of $2.7 million for certain accounts receivable attributable to natural gas imbalances accounted for under the entitlements method prior to January 1, 2018, in connection with the adoption of ASC Topic 606 (see Note 5).

15. Share-Based Compensation and Other Benefit Plans

Share-Based Compensation

We recognize share-based compensation expense related to our share-based compensation plans as a component of G&A expenses in our Condensed Consolidated Statements of Operations.

We reserved 749,600 shares of common stock for issuance under the Penn Virginia Corporation Management Incentive Plan for future share-based compensation awards. A total of 322,437 RSUs and 98,526 PRSUs have been granted as of June 30, 2018.

We recognized $0.9 million and $0.8 million and $2.5 million and $1.7 million of expense attributable to the RSUs and PRSUs for the three and six months ended June 30, 2018 and 2017, respectively. Approximately $0.6 million of the expense for the 2018 six-month period was attributable to the accelerated vesting of certain awards of our former Executive Chairman.

In the six months ended June 30, 2018 and 2017, we granted 17,456 and 148,837 RSUs to certain employees with an average grant-date fair value of $43.43 and $51.50 per RSU, respectively. The RSUs are being charged to expense on a straight-line basis over a range of four to five years. In the six months ended June 30, 2018, 38,115 shares vested, net of shares withheld for income taxes.

In the six months ended June 30, 2017, we granted 62,675 PRSUs to members of our management. No PRSUs were granted during the six months ended June 30, 2018. In the six months ended June 30, 2018, 1,495 shares vested, net of shares withheld for income taxes. Previously-issued PRSUs were issued collectively in two to three separate tranches with individual three-year performance periods beginning in January 2017, 2018 and 2019, respectively. Vesting of the PRSUs can range from zero to 200 percent of the original grant based on the performance of our common stock relative to an industry index. Due to their market condition, the PRSUs are being charged to expense using graded vesting over a maximum of five years. The fair value of each PRSU award was estimated on their grant dates using a Monte Carlo simulation with a range of $47.70 to $65.28 per PRSU. Expected volatilities were based on historical volatilities and range from 59.63% to 62.18%. A risk-free rate of interest with a range of 1.44% to 1.51% was utilized, which is equivalent to the yield, as of the measurement date, of the zero-coupon U.S. Treasury bill commensurate with the longest remaining performance measurement period for each tranche. We assumed no payment of dividends during the performance periods.

Other Benefit Plans

We maintain the Penn Virginia Corporation and Affiliated Companies Employees 401(k) Plan (the “401(k) Plan”), a defined contribution plan, which covers substantially all of our employees. We recognized $0.2 million and $0.3 million of expense attributable to the 401(k) Plan for the three and six months ended June 30, 2018, respectively, and $0.1 million and $0.2 million for the three and six months ended June 30, 2017, respectively. The charges for the 401(k) Plan are recorded as a component of G&A expenses.

We maintain unqualified legacy defined benefit pension and defined benefit postretirement plans that cover a limited number of former employees, all of whom retired prior to 2000. The combined expense recognized with respect to these plans was less than $0.1 million for each of the three and six months ended June 30, 2018 and 2017. The charges for these plans are recorded as a component of “Other income (expense)” in our Condensed Consolidated Statements of Operation.

16. Interest Expense

The following table summarizes the components of interest expense for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Interest on borrowings and related fees	$ 7,730	$ 515	$ 13,778	$ 905
Accretion of original issue discount [1]	168	—	333	—
Amortization of debt issuance costs	680	800	1,311	988
Capitalized interest	(2,428)	(41)	(4,671)	(81)
	$ 6,150	$ 1,274	$ 10,751	$ 1,812

[1] Attributable to the Second Lien Facility (see Note 8).

17. Earnings per Share

The following table provides a reconciliation of the components used in the calculation of basic and diluted earnings per share for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net income (loss) - basic and diluted	$ (2,521)	$ 21,329	$ 7,774	$ 49,410
Weighted-average shares – basic	15,058	14,992	15,050	14,992
Effect of dilutive securities [1]	—	58	121	105
Weighted-average shares – diluted	15,058	15,050	15,171	15,097

[1] For the three months ended June 30, 2018, approximately 0.1 million potentially dilutive securities, represented by RSUs and PRSUs, had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per share.

Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. We use words such as “anticipate,” “guidance,” “assumptions,” “projects,” “estimates,” “expects,” “continues,” “intends,” “plans,” “believes,” “forecasts,” “future,” “potential,” “may,” “possible,” “could” and variations of such words or similar expressions to identify forward-looking statements. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following:

- risks related to completed acquisitions, including our ability to realize their expected benefits;
- our ability to satisfy our short-term and long-term liquidity needs, including our inability to generate sufficient cash flows from operations or to obtain adequate financing to fund our capital expenditures and meet working capital needs;
- negative events or publicity adversely affecting our ability to maintain our relationships with our suppliers, service providers, customers, employees, and other third parties;
- plans, objectives, expectations and intentions contained in this report that are not historical;
- our ability to execute our business plan in volatile and depressed commodity price environments;
- the impact of our review of strategic options and any resulting potential transaction, including our ability to execute, market reactions, costs and focus from management;
- the decline in and volatility of commodity prices for oil, NGLs, and natural gas;
- our ability to develop, explore for, acquire and replace oil and natural gas reserves and sustain production;
- our ability to generate profits or achieve targeted reserves in our development and exploratory drilling and well operations;
- any impairments, write-downs or write-offs of our reserves or assets;
- the projected demand for and supply of oil, natural gas liquids, or NGLs, and natural gas;
- our ability to contract for drilling rigs, frac crews, supplies and services at reasonable costs;
- our ability to renew or replace expiring contracts on acceptable terms;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production at reasonable cost and to sell our production at, or at reasonable discounts to, market prices;
- the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from that estimated in our proved oil and natural gas reserves;
- drilling and operating risks;
- our ability to compete effectively against other oil and gas companies;
- leasehold terms expiring before production can be established and our ability to replace expired leases;
- environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements with other parties and counterparty risk related to the ability of these parties to meet their future obligations;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key employees;
- our reliance on a limited number of customers and a particular region for a majority of our revenues and production;
- compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters;
- the implementation and impact of the Tax Cuts and Jobs Act;
- physical, electronic and cybersecurity breaches;
- uncertainties relating to general domestic and international economic and political

conditions;

- the impact and costs associated with litigation or other legal matters; and
- other factors set forth in our periodic filings with the Securities and Exchange Commission, including the risks set forth in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2017.

Additional information concerning these and other factors can be found in our press releases and public filings with the Securities and Exchange Commission. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management's views only as of the date hereof. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable law.

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

The following discussion and analysis of the financial condition and results of operations of Penn Virginia Corporation and its consolidated subsidiaries ("Penn Virginia," the "Company," "we," "us" or "our") should be read in conjunction with our Condensed Consolidated Financial Statements and Notes thereto included in Part I, Item 1, "Financial Statements." All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated. Also, due to the combination of different units of volumetric measure, the number of decimal places presented and rounding, certain results may not calculate explicitly from the values presented in the tables. References to "quarters" represent the three months ended June 30, 2018 or 2017, as applicable.

Overview and Executive Summary

We are an independent oil and gas company engaged in the onshore exploration, development and production of crude oil, natural gas liquids, or NGLs, and natural gas. Our current operations consist primarily of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale, or the Eagle Ford, in Gonzales, Lavaca and DeWitt Counties in South Texas.

Crude oil prices have continued in a steadily rising trend that began in the second half of 2017 throughout the six months ended June 30, 2018 and into the mid-summer season. Because of the proximity of our operating region to the Gulf Coast markets, we sell substantially all of our crude oil production based on the Light Louisiana Sweet, or LLS, price index. The LLS index has exceeded that of the West Texas Intermediate, or WTI, price index, providing us with a strong revenue stream compared to certain of our domestic peers and competitors further inland. With the improved pricing environment, domestic production has increased, including that in the broader Eagle Ford region in which we operate. This environment has expanded opportunities in our principal operating region. Furthermore, many exploration and production companies that experienced financial difficulties similar to us during the 2015 and 2016 time frame have restructured and refocused their financial resources and operating plans to capitalize on current opportunities. In addition, there has been a consolidation of holdings within the Eagle Ford, including our own, through recent acquisitions. Collectively, these and other factors have led to higher pricing for certain oilfield products and services, including drilling and completion services, which we expect to continue in the intermediate term.

As discussed in further detail in Notes 2 and 5 to the Condensed Consolidated Financial Statements, we have adopted two new accounting standards: Accounting Standards Codification Topic 606, *Revenues from Contracts with Customers*, or ASC Topic 606, and Accounting Standards Update 2017–07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, or ASU 2017–07, effective January 1, 2018. The adoption of these standards impacts the presentation and comparability of (i) NGL product revenues and Gathering, processing and transportation, or GPT, expense and (ii) General and administrative, or G&A, expenses and Other income (expense), net. We adopted ASC Topic 606 utilizing the cumulative effect transition method. Accordingly, our NGL revenues and GPT expense for the three and six months ended June 30, 2017 are not comparable to the 2018 presentation of these items. Our discussion and analysis of these items in the *Results of Operations* that follow address the effects of changes directly attributable to the adoption of ASC Topic 606. We adopted ASU 2017–07 utilizing the modified retrospective method. Accordingly, certain benefits costs that were previously reported as a component of G&A are being reported as a component of Other, net (expenses), as required by ASU 2017–07, for all periods presented.

The following summarizes our key operating and financial highlights for the three months ended June 30, 2018, with comparison to the three months ended March 31, 2018. The year-over-year highlights are addressed in further detail in the discussions for *Financial Condition* and *Results of Operations* that follow.

- Production increased approximately 39 percent to 2,020 thousand barrels of oil equivalent, or MBOE, from 1,453 MBOE due primarily to a greater number of wells turned to sales, as well as the effect of a full quarter of production from increased working interests in wells associated with the acquisition of certain oil and gas assets from Hunt Oil Company, or Hunt, in March 2018, or the Hunt Acquisition.
- Product revenues increased approximately 44 percent to $111.2 million from $77.0 million due primarily to 33 percent higher crude oil volume and seven percent higher crude oil prices. Higher NGL and natural gas revenues from 53 percent higher volumes and 15 percent higher NGL pricing were partially offset by 10 percent lower natural gas pricing.
- Production and lifting costs (consisting of Lease operating expenses, or LOE, and GPT) increased on an absolute basis to $13.3 million from $10.7 million, but declined on a per unit basis to $6.58 per barrel of oil equivalent, or BOE, from $7.33 per BOE due primarily to the increase in production volume in the second quarter of 2018.
- Production and ad valorem taxes increased on an absolute and per unit basis to $5.8 million and $2.87 per BOE from $4.1 million and $2.82 per BOE, respectively, due to higher production volume and higher crude oil and NGL pricing.

- G&A expenses decreased on an absolute and per unit basis to $5.3 million and $2.63 per BOE from $6.5 million and $4.45 per BOE, respectively, due primarily to the effect of higher production volume in the second quarter of 2018 and certain acquisition transaction and executive-retirement-related costs that were incurred the first quarter of 2018 partially offset by higher employee-related support costs in the second quarter as we have expanded our employee base commensurate with our current growth plans.
- Depreciation, depletion and amortization, or DD&A, increased on an absolute and per unit basis to $31.3 million and $15.48 per BOE from $22.1 million and $15.20 per BOE, respectively, due primarily to higher production volume and the effects of higher drilling and completion costs and property costs from the Hunt Acquisition.
- Operating income increased to $55.9 million from $33.9 million due to the combined impact of the matters noted in the bullets above.

The following table sets forth certain historical summary operating and financial statistics for the periods presented:

	Three Months Ended			Six Months Ended	
	June 30,	March 31,	June 30,	June 30,	
	2018	2018	2017	2018	2017
Total production (MBOE)	2,020	1,453	925	3,473	1,779
Average daily production (BOEPD)	22,200	16,145	10,159	19,189	9,829
Crude oil production (MBbl)	1,498	1,127	685	2,625	1,293
Crude oil production as a percent of total	74%	78%	74%	76%	73%
Product revenues	$ 111,161	$ 76,994	$ 36,274	$ 188,155	$ 70,992
Crude oil revenues	$ 101,716	$ 71,258	$ 32,351	$ 172,974	$ 62,424
Crude oil revenues as a percent of total	92%	93%	89%	92%	88%
Realized prices:					
Crude oil ($ per Bbl)	$ 67.89	$ 63.23	$ 47.25	$ 65.89	$ 48.29
NGLs ($ per Bbl) [1]	$ 20.54	$ 17.94	$ 15.59	$ 19.56	$ 17.38
Natural gas ($ per Mcf)	$ 2.58	$ 2.87	$ 2.88	$ 2.70	$ 2.98
Aggregate ($ per BOE)	$ 55.02	$ 52.99	$ 39.24	$ 54.17	$ 39.90
Prices adjusted for derivatives:					
Crude oil ($ per Bbl)	$ 59.61	$ 56.51	$ 46.57	$ 58.28	$ 46.39
Aggregate ($ per BOE)	$ 48.89	$ 47.77	$ 38.73	$ 48.42	$ 38.52
Production and lifting costs:					
Lease operating ($ per BOE)	$ 4.32	$ 5.02	$ 5.81	$ 4.61	$ 5.78
Gathering, processing and transportation ($ per BOE) [1]	$ 2.26	$ 2.31	$ 2.76	$ 2.28	$ 2.87
Production and ad valorem taxes ($ per BOE)	$ 2.87	$ 2.82	$ 2.29	$ 2.85	$ 2.30
General and administrative ($ per BOE) [2]	$ 2.63	$ 4.45	$ 4.00	$ 3.40	$ 4.39
Depreciation, depletion and amortization ($ per BOE)	$ 15.48	$ 15.20	$ 11.97	$ 15.36	$ 11.74
Capital expenditure program costs [3]	$ 125,035	$ 84,228	$ 25,037	$ 209,263	$ 44,796
Cash provided by operating activities [4]	$ 81,736	$ 38,682	$ 26,875	$ 120,418	$ 36,017
Cash paid for capital expenditures [5]	$ 123,511	$ 77,839	$ 25,842	$ 201,350	$ 43,583
Cash and cash equivalents at end of period	$ 11,521	$ 7,319	$ 10,105	$ 11,521	$ 10,105
Debt outstanding at end of period, net	$ 432,824	$ 383,766	$ 37,000	$ 432,824	$ 37,000
Credit available under credit facility at end of period	$ 95,745	$ 144,245	$ 162,245	$ 95,745	$ 162,245
Net development wells drilled and completed	16.9	10.0	3.0	26.9	6.6

[1] The effects of the adoption of ASC Topic 606, if applied to the periods ended in 2017, would have resulted in realized prices for NGLs of $13.02 and $14.65 per BOE and GPT of $2.40 and $2.49 per BOE for the three and six months ended June 30, 2017 , respectively.

[2] Includes combined amounts of $0.46, $1.55 and $0.91 per BOE for the three months ended June 30, 2018, March 31, 2018 and June 30, 2017, respectively, and $0.92 and $0.94 per BOE for the six months ended June 30, 2018 and 2017, respectively, attributable to equity-classified share-based compensation and significant special charges, including acquisition and divestiture transaction and other costs, as described in the discussion of "*Results of Operations - General and Administrative*" that follows.

[3] Includes amounts accrued and excludes capitalized interest and capitalized labor.

[4] Includes cash paid for derivative settlements of $12.4 million, $7.6 million and $0.5 million for the three months ended June 30, 2018, March 31, 2018 and June 30, 2017, respectively, and $20.0 million and $2.5 million for the six months ended June 30, 2018 and 2017, respectively. Reflects changes in operating assets and liabilities of $11.4 million, $(7.4) million and $4.2 million for the the three months ended June 30, 2018 , March 31, 2018 and June 30, 2017, respectively, and $4.0 million and $(6.5) million for the six months ended June 30, 2018 and 2017, respectively.

[5] Represents actual cash paid for capital expenditures including capitalized interest and capitalized labor.

Key Developments

The following general business developments had or may have a significant impact on our results of operations, financial position and cash flows:

Initiative to Evaluate Strategic Alternatives

On July 23, 2018, we announced that the Board of Directors intends to evaluate a range of strategic alternatives to enhance shareholder value, including without limitation, a corporate sale, merger or other business combination, one or more strategic acquisitions, or other transactions. There is no assurance that the evaluation process will result in a transaction, and we will incur additional expenses as a result of this evaluation process.

Production and Development Plans

Total production for the second quarter of 2018 was 2,020 MBOE, or 22,200 barrels of oil equivalent per day, or BOEPD, with approximately 74 percent, or 1,498 MBOE, of production from crude oil, 13 percent from NGLs and 13 percent from natural gas. Production from our Eagle Ford operations during this period was 1,952 MBOE or 21,450 BOEPD. Approximately 76 percent of our Eagle Ford production for the period was from crude oil, 13 percent was from NGLs and 11 percent was from natural gas. Production from our Eagle Ford operations was approximately 97 percent of total Company production during the second quarter of 2018.

We drilled and turned 20 gross (16.9 net) Eagle Ford wells to sales during the second quarter of 2018. Subsequent to June 30, 2018, we drilled and turned an additional two gross (1.7 net) wells from the Hawn Holt pad to sales. As of August 3, 2018, we were drilling six gross (5.1 net) wells with our three operated drilling rigs, four gross (3.9 net) wells were completing and one gross (1.0 net) well was waiting on completion.

As of August 3, 2018, we had approximately 97,900 gross (84,060 net) acres in the Eagle Ford, net of expirations. Approximately 92 percent of our acreage is held by production and substantially all is operated by us.

Acquisition of Producing Properties

In December 2017, we entered into a purchase and sale agreement with Hunt to acquire certain oil and gas assets in the Eagle Ford Shale, primarily in Gonzales and Lavaca Counties, Texas for $86.0 million in cash, subject to adjustments. The Hunt Acquisition had an effective date of October 1, 2017, and closed on March 1, 2018, at which time we paid cash consideration of $84.4 million. In connection with the Hunt Acquisition, we also acquired working interests in certain wells that we previously drilled as operator, and in which Hunt had rights to participate prior to the transaction closing. Accumulated costs, net of suspended revenues for these wells was $13.8 million, which we have reflected as a component of the total net assets acquired. The Hunt Acquisition expanded our net leasehold position by approximately 9,700 net acres, substantially all of which is held by production, in the northwestern portion of our Eagle Ford acreage.

Commodity Hedging Program

As of August 3, 2018, we have hedged a portion of our estimated future crude oil production through the end of 2020 with a mix of WTI- and LLS- indexed swaps. We are currently unhedged with respect to NGL and natural gas production. The following table summarizes our hedge positions for the periods presented:

	WTI Volumes (Barrels per day)	WTI Average Swap Price ($ per barrel)	LLS Volumes (Barrels per day)	LLS Average Swap Price ($ per barrel)
Remainder of 2018	10,455	$ 57.05	6,000	$ 65.27
2019	6,415	$ 54.48	5,000	$ 59.17
2020	6,000	$ 54.09	—	—

Divestiture of Mid-Continent Properties

In June 2018, we entered into a purchase and sale agreement with a third party to sell all of our remaining Mid-Continent oil and gas properties, located primarily in Oklahoma in the Granite Wash, for $6 million in cash, subject to customary adjustments. We received a deposit of $0.7 million in June 2018. The sale has an effective date of March 1, 2018, and closed on July 31, 2018, at which time we received proceeds of $5.5 million.

Financial Condition

Liquidity

Our primary sources of liquidity include our cash on hand, cash provided by operating activities and borrowings under the Credit Facility. The Credit Facility provides us with up to $340 million in borrowing commitments. The current borrowing base under the Credit Facility is also $340 million. As of August 3, 2018, we had $71.7 million available under the Credit Facility.

Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for crude oil, NGL and natural gas products, as well as variations in our production. The prices for these commodities are driven by a number of factors beyond our control, including global and regional product supply and demand, weather, product distribution, refining and processing capacity and other supply chain dynamics, among other factors. The level of our hedging activity and duration of the financial instruments employed depend on our desired cash flow protection, available hedge prices, the magnitude of our capital program and our operating strategy. In order to mitigate this volatility, we entered into derivative contracts hedging a portion of our estimated future crude oil production through the end of 2020.

Capital Resources

Under our capital program for 2018, we anticipate capital expenditures, excluding acquisitions, to total between $390 million and $410 million for 2018 with approximately 96 percent of capital being directed to drilling and completions on our Eagle Ford acreage. We plan to fund our 2018 capital spending with cash from operating activities and borrowings under the Credit Facility. Based upon current price and production expectations for 2018, we believe that our cash from operating activities and borrowings under our Credit Facility will be sufficient to fund our operations through year-end 2018; however, future cash flows are subject to a number of variables and significant additional capital expenditures may be required to more fully develop our properties. For a detailed analysis of our historical capital expenditures, see the "*Cash Flows*" discussion that follows.

Cash on Hand and Cash From Operating Activities. As of August 3, 2018, we had approximately $9.4 million of cash on hand. For additional information and an analysis of our historical cash from operating activities, see the "*Cash Flows*" discussion that follows.

Credit Facility Borrowings. During the three and six-months ended June 30, 2018, we borrowed $48.5 million and $166.5 million, respectively, under the Credit Facility, with a substantial portion borrowed during the first quarter of 2018 to fund the Hunt Acquisition. For additional information regarding the terms and covenants under the Credit Facility, see the "*Capitalization*" discussion that follows.

The following table summarizes our borrowing activity under the Credit Facility for the periods presented:

	Borrowings Outstanding		
	Weighted-Average	**Maximum**	**Weighted-Average Rate**
Three months ended June 30, 2018	$ 224,370	$ 243,500	5.44%
Six months ended June 30, 2018	$ 179,939	$ 243,500	5.28%

Proceeds from Sales of Assets. We continually evaluate potential sales of non-core assets, including certain oil and gas properties and non-strategic undeveloped acreage, among others. For additional information and an analysis of our historical proceeds from sales of assets, see the "*Cash Flows*" discussion that follows.

Capital Market Transactions. From time-to-time and under market conditions that we believe are favorable to us, we may consider capital market transactions, including the offering of debt and equity securities.

Cash Flows

The following table summarizes our cash flows for the periods presented:

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Cash flows from operating activities		
Operating cash flows, net of working capital changes	$ 150,502	$ 40,171
Crude oil derivative settlements paid, net	(19,977)	(2,458)
Interest payments, net of amounts capitalized	(8,953)	(795)
Acquisition and divestiture transaction costs paid	(462)	—
Bankruptcy-related administration fees and costs paid	(442)	(901)
Consulting costs paid to former Executive Chairman	(250)	—
Net cash provided by operating activities	120,418	36,017
Cash flows from investing activities		
Acquisitions, net	(86,835)	—
Capital expenditures	(201,350)	(43,583)
Proceeds from sales of assets, net	2,525	—
Net cash used in investing activities	(285,660)	(43,583)
Cash flows from financing activities		
Proceeds from credit facility borrowings, net	166,500	12,000
Debt issuance costs paid	(754)	(1,090)
Proceeds received from rights offering, net	—	55
Other, net	—	(55)
Net cash provided by financing activities	165,746	10,910
Net increase in cash and cash equivalents	$ 504	$ 3,344

Cash Flows from Operating Activities. The increase in net cash from operating activities for the six months ended June 30, 2018 compared to the corresponding period in 2017 was primarily attributable to: (i) higher production volume in the 2018 period, (ii) incremental net operating cash inflows from the Hunt Acquisition and the 2017 acquisition of oil and gas assets from Devon Energy Corporation, or the Devon Acquisition, (iii) higher crude oil pricing in the 2018 period and (iv) lower payments in the 2018 period for bankruptcy-related administration costs. These items were partially offset by: (i) higher settlements paid for crude oil derivatives, (ii) higher interest payments due to greater outstanding borrowings in the 2018 period, (iii) transaction costs paid in the 2018 period in connection with the Hunt and Devon Acquisitions and the Mid-Continent divestiture and (iv) certain costs paid in connection with the retirement of our Executive Chairman in February 2018.

Cash Flows from Investing Activities. In the 2018 period, we paid a combined total of $87.9 million for the Hunt Acquisition and the purchase of other working interests in producing properties in the Eagle Ford and received a total of $1.1 million in connection with the final settlement of the Devon Acquisition. As illustrated in the tables below, our cash payments for capital expenditures were substantially higher during the 2018 period as compared to the 2017 period, due primarily to the employment of three drilling rigs and a second frac spread in our current drilling program as opposed to two drilling rigs and one frac spread during the 2017 period as well as the effect of higher working interests from the Hunt and Devon Acquisitions. In addition, we received proceeds of $1.8 million in the 2018 period attributable to the sales of: (i) undeveloped acreage holdings in the Tuscaloosa Marine Shale in Louisiana, (ii) certain undeveloped deep leasehold rights in Oklahoma, (iii) certain pipeline assets in our former Marcellus Shale operating region and (iv) scrap tubular and well materials. We also received a deposit of $0.7 million in June 2018 in connection with the Mid-Continent divestiture.

The following table sets forth costs related to our capital expenditures program for the periods presented:

	Six Months Ended	
	June 30, 2018	June 30, 2017
Drilling and completion	$ 202,848	$ 43,455
Lease acquisitions and other land-related costs	2,886	1,402
Pipeline, gathering facilities and other equipment, net	3,344	(443)
Geological and geophysical (seismic) costs	185	382
	$ 209,263	$ 44,796

The following table reconciles the total costs of our capital expenditures program with the net cash paid for capital expenditures as reported in our Condensed Consolidated Statements of Cash Flows for the periods presented:

	Six Months Ended	
	June 30, 2018	June 30, 2017
Total capital expenditures program costs (from above)	$ 209,263	$ 44,796
Increase in accrued capitalized costs	(12,231)	(2,322)
Less:		
Transfers from tubular inventory and well materials	(4,006)	(1,142)
Sales and use tax refunds received and applied to property accounts	(644)	—
Add:		
Tubular inventory and well materials purchased in advance of drilling	2,677	1,100
Capitalized internal labor	1,620	1,070
Capitalized interest	4,671	81
Total cash paid for capital expenditures	$ 201,350	$ 43,583

Cash Flows from Financing Activities. The 2018 period includes borrowings of $166.5 million under the Credit Facility, a substantial portion of which were used to fund the Hunt Acquisition, while the 2017 period only includes borrowings of $14 million and repayments of $2 million. We also paid $0.8 million of debt issue costs in the 2018 period in connection with amendments to the Credit Facility and other costs in connection with the $200 million Second Lien Facility, or Second Lien Facility, compared to $1.1 million paid in the 2017 period in connection with an amendment to the Credit Facility. The receipt in the 2017 period of delayed proceeds attributable to the rights offering in September 2016 were fully offset by costs paid in connection with the registration of our common stock in the 2017 period.

Capitalization

The following table summarizes our total capitalization as of the dates presented:

	June 30, 2018	December 31, 2017
Credit Facility borrowings	$ 243,500	$ 77,000
Second Lien Facility term loan, net	189,324	188,267
Total debt, net	432,824	265,267
Shareholders' equity	228,612	221,639
	$ 661,436	$ 486,906
Debt as a % of total capitalization	65%	54%

Credit Facility. The Credit Facility provides for a $340 million revolving commitment and borrowing base. The Credit Facility includes a $5.0 million sublimit for the issuance of letters of credit. The availability under the Credit Facility may not exceed the lesser of the aggregate commitments or the borrowing base. The borrowing base under the Credit Facility is redetermined semi-annually, generally in April and October of each year. Additionally, the Credit Facility lenders may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us for general corporate purposes including working capital. The Credit Facility matures in September 2020. We had $0.8 million in letters of credit outstanding as of June 30, 2018 and December 31, 2017.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 2.00% to 3.00%, determined based on the average availability under the Credit Facility or (b) a customary London interbank offered rate, or LIBOR, plus an applicable margin ranging from 3.00% to 4.00%, determined based on the average availability under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on LIBOR borrowings is payable every one, three or six months, at our election, and is computed on the basis of a year of 360 days. As of June 30, 2018, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 5.58%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility is guaranteed by us and all of our subsidiaries, or the Guarantor Subsidiaries. The guarantees under the Credit Facility are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. There are no significant restrictions on our ability or any of the Guarantor Subsidiaries to obtain funds through dividends, advances or loans. The obligations under the Credit Facility are secured by a first priority lien on substantially all of our assets.

Second Lien Facility. On September 29, 2017, we entered into the Second Lien Facility. The maturity date under the Second Lien Facility is September 29, 2022.

The outstanding borrowings under the Second Lien Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate based on the prime rate plus an applicable margin of 6.00% or (b) a customary LIBOR rate plus an applicable margin of 7.00%. Amounts under the Second Lien Facility were borrowed at a price of 98% with an initial interest rate of 8.34% resulting in an effective interest rate of 9.89%. As of June 30, 2018, the actual interest rate on the Second Lien Facility was 9.10%. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on eurocurrency borrowings is payable every one or three months (including in three month intervals if we select a six month interest period), at our election and is computed on the basis of a year of 360 days. We have the right, to the extent permitted under the Credit Facility and an intercreditor agreement between the lenders under the Credit Facility and the lenders under the Second Lien Facility, to prepay loans under the Second Lien Facility at any time, subject to the following prepayment premiums (in addition to customary "breakage" costs with respect to eurocurrency loans): during year one, a customary "make-whole" premium; during year two, 102% of the amount being prepaid; during year three, 101% of the amount being prepaid; and thereafter, no premium. The Second Lien Facility also provides for the following prepayment premiums in the event of a change in control that results in an offer of prepayment that is accepted by the lenders under the Second Lien Facility: during years one and two, 102% of the amount being prepaid; during year three, 101% of the amount being prepaid; and thereafter, no premium.

The Second Lien Facility is collateralized by substantially all of the Company's and its subsidiaries' assets with lien priority subordinated to the liens securing the Credit Facility. The obligations under the Second Lien Facility are guaranteed by us and the Guarantor Subsidiaries.

Covenant Compliance. The Credit Facility requires us to maintain (1) a minimum interest coverage ratio (adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses as defined in the Credit Facility, or EBITDAX, to adjusted interest expense), measured as of the last day of each fiscal quarter, of 3.00 to 1.00, (2) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset), measured as of the last day of each fiscal quarter of 1.00 to 1.00, and (3) a maximum leverage ratio (consolidated indebtedness to EBITDAX), measured as of the last day of each fiscal quarter of 3.50 to 1.00.

The Credit Facility and Second Lien Facility also contain customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports and budgets, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens and indebtedness, merger, consolidation or sale of assets, payment of dividends, and transactions with affiliates and other customary covenants.

The Credit Facility and Second Lien Facility contain customary events of default and remedies. If we do not comply with the financial and other covenants in the Credit Facility and Second Lien Facility, the lenders thereto may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility and Second Lien Facility.

As of June 30, 2018, we were in compliance with all of the covenants under the Credit Facility and the Second Lien Facility.

Results of Operations

Production

The following tables set forth a summary of our total and average daily production volumes by product and geographic region for the periods presented:

	Total Production			Average Daily Production		
	Three Months Ended		2018 vs. 2017	Three Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Crude oil (MBbl and BOPD)	1,498	685	813	16,465	7,524	8,941
NGLs (MBbl and BOPD)	269	131	138	2,960	1,440	1,520
Natural gas (MMcf and MMcfpd)	1,515	653	862	17	7	10
Total (MBOE and BOEPD)	2,020	925	1,096	22,200	10,159	12,041

	Three Months Ended		2018 vs. 2017	Three Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
	(MBOE)			(BOEPD)		
South Texas	1,952	864	1,088	21,451	9,498	11,953
Mid-Continent	68	60	8	749	662	88
	2,020	925	1,096	22,200	10,159	12,041

	Six Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Crude oil (MBbl and BOPD)	2,625	1,293	1,332	14,505	7,142	7,363
NGLs (MBbl and BOPD)	434	250	184	2,395	1,381	1,014
Natural gas (MMcf and MMcfpd)	2,486	1,418	1,068	14	8	6
Total (MBOE and BOEPD)	3,473	1,779	1,694	19,189	9,829	9,360

	Six Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
	(MBOE)			(BOE per day)		
South Texas	3,335	1,635	1,700	18,427	9,032	9,395
Mid-Continent	138	144	(6)	762	797	(35)
	3,473	1,779	1,694	19,189	9,829	9,360

Total production increased during the three and six month periods in 2018 when compared to the corresponding periods in 2017 due primarily to more productive and a greater number of wells turned to sales in the 2018 periods as well as incremental production from the Hunt and Devon Acquisitions. Additionally, we operated three drilling rigs during the 2018 periods as compared to two during the 2017 periods, the second of which was not contracted until mid-March 2017. These increases were partially offset by natural production declines in our former Mid-Continent wells where we have not drilled a new well since 2013, as well as certain of our legacy Eagle Ford wells.

Approximately 74 percent and 76 percent of total production during the three and six month periods in 2018 was attributable to crude oil when compared to approximately 74 percent and 73 percent during the corresponding periods in 2017. The marginal decrease in the crude oil composition during the three month period in 2018 was attributable to certain wells that were turned to sales in the southernmost portion of our Eagle Ford acreage that have a more significant natural gas content compared to our typical Eagle Ford well profile. Our Eagle Ford production represented 97 percent and 96 percent of our total production during the three and six month periods in 2018 compared to approximately 93 percent and 92 percent from this region during the corresponding periods in 2017. During the three and six month periods in 2018, we turned 20 gross (16.9 net) and 33 gross (26.9 net) Eagle Ford wells to sales compared to seven gross (3.0 net) and 13 gross (6.6 net) wells during the corresponding periods in 2017. While we resumed our drilling program in November 2016, we did not turn any new wells to sales until mid-February 2017.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per unit of volume by product and geographic region for the periods presented:

	Total Product Revenues			Product Revenues per Unit of Volume		
	Three Months Ended		2018 vs. 2017	Three Months Ended		2018 vs. 2017
	June 30, 2018	June 30, 2017	Favorable (Unfavorable)	June 30, 2018	June 30, 2017	Favorable (Unfavorable)
				($ per unit of volume)		
Crude oil	$ 101,716	$ 32,351	$ 69,365	$ 67.89	$ 47.25	$ 20.64
NGLs	5,533	2,043	3,490	$ 20.54	$ 15.59	$ 4.95
Natural gas	3,912	1,880	2,032	$ 2.58	$ 2.88	$ (0.30)
Total	$ 111,161	$ 36,274	$ 74,887	$ 55.02	$ 39.24	$ 15.78

	Three Months Ended		2018 vs. 2017	Three Months Ended		2018 vs. 2017
	June 30, 2018	June 30, 2017	Favorable (Unfavorable)	June 30, 2018	June 30, 2017	Favorable (Unfavorable)
				($ per BOE)		
South Texas	$ 109,544	$ 34,916	$ 74,628	$ 56.12	$ 40.40	$ 15.72
Mid-Continent	1,617	1,358	259	$ 23.71	$ 22.55	$ 1.16
	$ 111,161	$ 36,274	$ 74,887	$ 55.02	$ 39.24	$ 15.78

	Six Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30, 2018	June 30, 2017	Favorable (Unfavorable)	June 30, 2018	June 30, 2017	Favorable (Unfavorable)
				($ per unit of volume)		
Crude oil	$ 172,974	$ 62,424	$ 110,550	$ 65.89	$ 48.29	$ 17.60
NGLs	8,479	4,345	4,134	$ 19.56	$ 17.38	$ 2.18
Natural gas	6,702	4,223	2,479	$ 2.70	$ 2.98	$ (0.28)
Total	$ 188,155	$ 70,992	$ 117,163	$ 54.17	$ 39.90	$ 14.27

	Six Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30, 2018	June 30, 2017	Favorable (Unfavorable)	June 30, 2018	June 30, 2017	Favorable (Unfavorable)
				($ per BOE)		
South Texas	$ 184,860	$ 67,603	$ 117,257	$ 55.43	$ 41.35	$ 14.08
Mid-Continent	3,295	3,389	(94)	$ 23.89	$ 23.49	$ 0.40
	$ 188,155	$ 70,992	$ 117,163	$ 54.17	$ 39.90	$ 14.27

The following table provides an analysis of the changes in our revenues for the periods presented:

	Three Months Ended June 30, 2018 vs. 2017			Six Months Ended June 30, 2018 vs. 2017		
	Revenue Variance Due to			Revenue Variance Due to		
	Volume	Price	Total	Volume	Price	Total
Crude oil	$ 38,444	$ 30,921	$ 69,365	$ 64,353	$ 46,197	110,550
NGLs	2,155	1,335	3,490	3,189	945	4,134
Natural gas	2,483	(451)	2,032	3,181	(702)	2,479
	$ 43,082	$ 31,805	$ 74,887	$ 70,723	$ 46,440	$ 117,163

Our product revenues during the three and six month periods in 2018 increased over the corresponding periods in 2017 due primarily to approximately 119 percent and 103 percent higher crude oil volumes and 44 percent and 36 percent higher crude oil prices, respectively. Our Eagle Ford crude oil production benefits from pricing based on the LLS index which has averaged approximately six percent and eight percent higher than the comparable WTI index during the three and six month periods in 2018, respectively. Higher natural gas revenues were primarily attributable to higher production volumes which were partially offset by the effect of 10 percent and nine percent lower natural gas pricing during the three and six month periods, respectively. Excluding the effects of the adoption of ASC Topic 606, or $0.6 million and $1.0 million, respectively, NGL pricing actually increased by 45 percent and 26 percent during the 2018 periods as compared to the corresponding periods in 2017.

Total crude oil revenues were approximately 92 percent of our total revenues during each of the three and six month periods in 2018 as compared to 89 percent and 88 percent during the three and six month periods in 2017. Total Eagle Ford revenues were approximately 99 percent and 98 percent of total revenues for the three and six month periods in 2018 and 96 percent and 95 percent for the corresponding periods in 2017.

Effects of Derivatives

The following table reconciles crude oil revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Crude oil revenues, as reported	$ 101,716	$ 32,351	$ 69,365	$ 172,974	$ 62,424	$ 110,550
Derivative settlements, net	(12,401)	(466)	(11,935)	(19,977)	(2,458)	(17,519)
	$ 89,315	$ 31,885	$ 57,430	$ 152,997	$ 59,966	$ 93,031
Crude oil prices per Bbl	$ 67.89	$ 47.25	$ 20.64	$ 65.89	$ 48.29	$ 17.60
Derivative settlements per Bbl	(8.28)	(0.68)	(7.60)	(7.61)	(1.90)	(5.71)
	$ 59.61	$ 46.57	$ 13.04	$ 58.28	$ 46.39	$ 11.89

Gain (Loss) on Sales of Assets

We recognize gains and losses on the sale or disposition of assets other than our oil and gas properties upon the completion of the underlying transactions. The following table sets forth the total gains and (losses) recognized for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Gain (loss) on sales of assets, net	$ 4	$ (134)	$ 138	$ 79	$ (69)	$ 148

There were insignificant net gains and losses recognized during each of the three and six month periods in 2018 and 2017 attributable to the disposition of certain support equipment, tubular inventory and well materials.

Other Revenues, net

Other revenues, net, includes fees for marketing, water disposal, gathering, transportation and compression that we charge to third parties, net of related expenses, as well as other miscellaneous revenues and credits attributable to our operations.

The following table sets forth the total other revenues, net recognized for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Other revenues, net	$ 415	$ 142	$ 273	$ 557	$ 345	$ 212

Other revenues, net increased during the three and six month periods in 2018 from the corresponding periods in 2017 due primarily to higher fees as described above charged to third parties due to substantially higher production upon which such fees are based.

Lease Operating Expenses

LOE includes costs that we incur to operate our producing wells and field operations. The most significant costs include compression and gas-lift, chemicals, water disposal, repairs and maintenance, including down-hole repairs, field labor, pumping and well-tending, equipment rentals, utilities and supplies, among others.

The following table sets forth our LOE for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Lease operating	$ 8,730	$ 5,370	$ (3,360)	$ 16,026	$ 10,286	$ (5,740)
Per unit of production ($ per BOE)	$ 4.32	$ 5.81	$ 1.49	$ 4.61	$ 5.78	$ 1.17
% change per unit of production			25.6%			20.2%

LOE increased on an absolute basis, but declined on a per unit basis during the three and six month periods in 2018 when compared to the corresponding periods in 2017. The absolute increases were due primarily to higher production volume including the incremental effects of the Devon and Hunt Acquisitions. The higher production volume also had the effect of decreasing the overall per unit cost, particularly those costs that have a higher fixed cost component. Furthermore, comprehensive maintenance costs in the second half of 2017 improved production and cost efficiency progressing into the 2018 periods.

Gathering, Processing and Transportation

GPT expense includes costs that we incur to gather and aggregate our crude oil, NGL and natural gas production from our wells and deliver them via pipeline or truck to a central delivery point, downstream pipelines or processing plants, and blend or process, as necessary, depending upon the type of production and the specific contractual arrangements that we have with the applicable midstream operators.

The following table sets forth our GPT expense for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Gathering, processing and transportation	$ 4,574	$ 2,555	$ (2,019)	$ 7,933	$ 5,106	$ (2,827)
Per unit of production ($ per BOE)	$ 2.26	$ 2.76	$ 0.50	$ 2.28	$ 2.87	$ 0.59
% change per unit of production			18.1%			20.6%

GPT expense increased on an absolute basis during the three and six month periods in 2018 when compared to the corresponding periods in 2017 due primarily to substantially higher production volumes as discussed above partially offset by the effect of the adoption of ASC Topic 606, or $0.6 million and $1.0 million, respectively. Per unit costs declined in the 2018 periods due primarily to the effect of the adoption of ASC Topic 606, or $0.28 and $0.29 per BOE, as well as the effect of additional production at the wellhead with no corresponding GPT expense subsequent to the achievement of required minimum crude oil volumes transported by pipeline within our Eagle Ford operating region.

Production and Ad Valorem Taxes

Production or severance taxes represent taxes imposed by the states in which we operate for the removal of resources including crude oil, NGLs and natural gas. Ad valorem taxes represent taxes imposed by certain jurisdictions, primarily counties, in which we operate, based on the value of our operating properties. The assessments for ad valorem taxes are generally based on contemporary commodity prices.

The following table sets forth our production and ad valorem taxes for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Production and ad valorem taxes						
Production/severance taxes	$ 5,291	$ 1,698	$ (3,593)	$ 8,900	$ 3,353	$ (5,547)
Ad valorem taxes	504	421	(83)	987	745	(242)
	$ 5,795	$ 2,119	$ (3,676)	$ 9,887	$ 4,098	$ (5,789)
Per unit production ($ per BOE)	$ 2.87	$ 2.29	$ (0.58)	$ 2.85	$ 2.30	$ (0.55)
Production/severance tax rate as a percent of product revenue	4.8%	4.7%		4.7%	4.7%	

Production taxes increased on both an absolute and per unit basis during the three and six month periods in 2018 when compared to the corresponding periods in 2017 due primarily to increased production volume and higher commodity sales prices. Accruals for ad valorem taxes have also increased for the 2018 periods as we have grown our assessable property base and we anticipate higher assessments as a result of higher commodity prices and increased working interests.

General and Administrative

Our G&A expenses include employee compensation, benefits and other related costs for our corporate management and governance functions, rent and occupancy costs for our corporate facilities, insurance, and professional fees and consulting costs supporting various corporate-level functions, among others. In order to facilitate a meaningful discussion and analysis of our results of operations with respect to G&A expenses, we have disaggregated certain costs into three components as presented in the table below. Primary G&A encompasses all G&A costs except share-based compensation and certain significant special charges that are generally attributable to material stand-alone transactions or corporate actions that are not otherwise in the normal course.

The following table sets forth the components of our G&A for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Primary G&A	$ 4,391	$ 2,854	$ (1,537)	$ 8,605	$ 6,135	$ (2,470)
Share-based compensation (equity-classified)	875	848	(27)	2,451	1,694	(757)
Significant special charges:						
Acquisition and divestiture transaction costs	56	—	(56)	487	—	(487)
Executive retirement costs	—	—	—	250	—	(250)
Restructuring expenses	—	—	—	—	(20)	(20)
Total G&A	$ 5,322	$ 3,702	$ (1,620)	$ 11,793	$ 7,809	$ (3,984)
Per unit of production ($ per BOE)	$ 2.63	$ 4.00	$ 1.37	$ 3.40	$ 4.39	$ 0.99
Per unit of production excluding share-based compensation and other significant special charges identified above ($ per BOE)	$ 2.17	$ 3.09	$ 0.92	$ 2.48	$ 3.45	$ 0.97

Our primary G&A expenses increased on an absolute and decreased on a per unit basis during the three and six month periods in 2018 compared to the corresponding periods in 2017. The absolute increase is due primarily to the effects of higher payroll, benefits and support costs attributable to a higher overall employee headcount. Higher production volume had the effect of reducing G&A per unit of production during the 2018 three and six month periods.

Equity-classified share-based compensation charges during the periods presented are attributable to the amortization of compensation cost associated with the grants of time-vested restricted stock units, or RSUs, and performance restricted stock units, or PRSUs. The grants of RSUs and PRSUs are described in greater detail in Note 15 to the Condensed Consolidated Financial Statements. A substantial portion of the share-based compensation expense is attributable to the RSU and PRSU grants made in the normal course in January 2017 and RSU grants in September 2016 in connection with our reorganization. The remainder is attributable to grants of RSUs and PRSUs to certain employees upon their hiring or as a result of promotion subsequent to the first quarter of 2017. The six month period in 2018 includes a charge of $0.6 million attributable to the accelerated vesting of certain RSUs and PRSUs in connection with the retirement of our Executive Chairman in February 2018.

During the second quarter of 2018, we incurred transaction costs associated with our Mid-Continent divestiture. In addition to these costs, the six month period of 2018 is comprised primarily of transaction costs associated with the Hunt Acquisition, including legal, due diligence and other professional fees. We also paid certain costs attributable to the retirement of our former Executive Chairman in February 2018 (see Note 10 to the Condensed Consolidated Financial Statements). The six month period in 2017 includes adjustments to severance-related restructuring accruals that were originally established in connection with our reorganization in 2016.

Depreciation, Depletion and Amortization

The following table sets forth total and per unit costs for DD&A for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
DD&A expense	$ 31,273	$ 11,076	$ (20,197)	$ 53,354	$ 20,886	$ (32,468)
DD&A Rate ($ per BOE)	$ 15.48	$ 11.97	$ (3.51)	$ 15.36	$ 11.74	$ (3.62)

DD&A increased on an absolute and per unit basis during the three and six month periods ended in 2018 when compared to the corresponding periods in 2017. Higher production volume provided for an increase of approximately $13.1 million and $19.9 million while $7.1 million and $12.6 million was attributable to the higher DD&A rates in the 2018 periods. The higher DD&A rates in the 2018 periods were attributable to costs added to the full cost pool, including those from the Devon and Hunt Acquisitions, during a period of rising crude oil prices while the DD&A rate for the 2017 period is based primarily on the fair value of our properties at the time of our emergence from bankruptcy in September 2016.

Interest Expense

The following table summarizes the components of our interest expense for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Interest on borrowings and related fees	$ 7,730	$ 515	$ (7,215)	$ 13,778	$ 905	$ (12,873)
Accretion of original issue discount	168	—	(168)	333	—	(333)
Amortization of debt issuance costs	680	800	120	1,311	988	(323)
Capitalized interest	(2,428)	(41)	2,387	(4,671)	(81)	4,590
	$ 6,150	$ 1,274	$ (4,876)	$ 10,751	$ 1,812	$ (8,939)

Interest expense increased during the three and six month periods in 2018 as compared to the corresponding periods in 2017 due primarily to higher outstanding balances under the Credit Facility, including amounts borrowed to fund our larger capital expenditure program in 2018 and the Hunt Acquisition, as well as interest attributable to the Second Lien Facility that was issued in September 2017 in order to fund the Devon Acquisition. Furthermore, the Credit Facility and the Second Lien Facility are variable-rate instruments and both have been subject to periodic increases in LIBOR rates on a consistent basis since the comparable periods in 2017. The accretion of original issue discount is entirely attributable to the Second Lien Facility and the amortization of debt issuance costs includes amounts attributable to both the Credit Facility and Second Lien Facility. We capitalized a larger portion of interest during each of the 2018 periods as we maintained a substantially larger portion of unproved property as compared to the corresponding periods in 2017 due primarily to the Devon Acquisition in September 2016.

Derivatives

The gains and losses for our derivatives portfolio reflect changes in the fair value attributable to changes in market values relative to our hedged commodity prices.

The following table summarizes the gains and (losses) attributable to our commodity derivatives portfolio, by commodity type, for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Crude oil derivative gains (losses)	$ (52,241)	$ 11,061	$ (63,302)	$ (71,036)	$ 28,077	$ (99,113)

In the three and six month periods in 2018, the forward curve for commodity prices was increasing relative to our weighted-average hedged prices while the forward curve for such prices declined relative to our weighted-average hedged prices in the comparable 2017 periods. We paid cash settlements of $12.4 million and $20.0 million and $0.5 million and $2.5 million in the three and six month periods in 2018 and 2017, respectively.

Other, net

Other, net includes interest income, non-service costs associated with our retiree benefit plans and miscellaneous items of income and expense that are not directly associated with our current operations, including certain recoveries and write-offs attributable to prior years and properties that have been divested.

The following table sets forth the other income (expense), net recognized for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Other, net	$ (16)	$ 82	$ (98)	$ (74)	$ 62	$ (136)

Other, net expense increased during the three and six month periods in 2018 as compared to the corresponding periods in 2017 due primarily to interest charges applicable to a settlement with a royalty owner. Each of the three and six month periods includes comparable charges associated with our retiree benefit plans, and the 2018 period is partially offset by interest income earned on the escrow account attributable to the Devon Acquisition prior to the escrow account’s liquidation in March 2018.

Income Taxes

The following table summarizes our income tax expense for the periods presented:

	Three Months Ended		2018 vs. 2017	Six Months Ended		2018 vs. 2017
	June 30,	June 30,	Favorable	June 30,	June 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Income tax expense	$ —	$ —	$ —	$ (163)	$ —	$ (163)
Effective tax rate	—%	—%		2.1%	—%	

On December 22, 2017, the U.S. Congress enacted comprehensive tax legislation as part of the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act, or the TCJA. The TCJA makes broad and complex changes to the U.S. tax code. The most significant aspects of the TCJA applicable to us include but are not limited to: (i) reducing the U.S. federal corporate income tax rate from 35% to 21%; (ii) allowing the immediate deduction of certain new investments in lieu of depreciation expense over time; (iii) creating a new limitation on deductible interest expense; (iv) changing rules related to use and limitations of net operating loss, or NOL, carryforwards created in tax years beginning after December 31, 2017 and (v) repeal of the corporate alternative minimum tax, or AMT.

In connection with our initial analysis of the impact of the TCJA, our Condensed Consolidated Balance Sheet as of December 31, 2017 included a deferred tax asset of $4.9 million attributable to our AMT credit carryforwards that were previously fully reserved, but became realizable in connection with the AMT provisions of the TCJA. We continue to analyze the impacts of the TCJA on the Company and refine our estimates during 2018.

We recognized federal and state income tax expense for the three and six-month periods in 2018 at a blended rate of 21.6%; however, the federal and state tax expenses were offset by adjustments to the valuation allowance against our net deferred tax assets along with an adjustment of $0.2 million for the six month period to the deferred tax asset related to sequestration of a portion of the aforementioned AMT credit carryforward resulting in an effective tax rate of 2.1%. The effect of the adjustment was to reduce our deferred tax asset to $4.8 million as of June 30, 2018. We recognized federal income tax benefits for the three and six months ended June 30, 2017 at the blended rate of 35.2% which was fully offset by a valuation allowance against our net deferred tax assets. We considered both the positive and negative evidence in determining that it was more likely than not that some portion or all of our deferred tax assets will not be realized, primarily as a result of cumulative losses.

Off Balance Sheet Arrangements

As of June 30, 2018, we had no off-balance sheet arrangements other than lease arrangements, information technology licensing, service agreements, employment agreements, in-kind commodity recovery arrangements for imbalances and letters of credit, all of which are customary in our business.

Critical Accounting Estimates

The process of preparing financial statements in accordance with accounting principles generally accepted in the United States of America, or GAAP, requires our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. Disclosure of our most critical accounting estimates that involve the judgment of our management can be found in our Annual Report on Form 10-K for the year ended December 31, 2017.

Disclosure of the Impact of Recently Issued Accounting Pronouncements Pending Adoption

In June 2016, the Financial Accounting Standards Board, or FASB, issued ASU 2016–13, *Measurement of Credit Losses on Financial Instruments*, or ASU 2016–13, which changes the recognition model for the impairment of financial instruments, including accounts receivable, loans and held-to-maturity debt securities, among others. ASU 2016–13 is required to be adopted using the modified retrospective method by January 1, 2020, with early adoption permitted for fiscal periods beginning after December 15, 2018. In contrast to current guidance, which considers current information and events and utilizes a probable threshold (an “incurred loss” model), ASU 2016–13 mandates an “expected loss” model. The expected loss model: (i) estimates the risk of loss even when risk is remote, (ii) estimates losses over the contractual life, (iii) considers past events, current conditions and reasonable supported forecasts and (iv) has no recognition threshold. ASU 2016–13 will have applicability to our accounts receivable portfolio, particularly those receivables attributable to our joint interest partners which have a higher credit risk than those associated with our traditional customer receivables. At this time, we do not anticipate that the adoption of ASU 2016–13 will have a significant impact on our Consolidated Financial Statements and related disclosures; however, we are continuing to evaluate the requirements and the period for which we will adopt the standard, as well as monitoring developments regarding ASU 2016–13 that are unique to our industry.

In February 2016, the FASB issued ASU 2016–02, *Leases*, or ASU 2016–02, which will require organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by those leases with terms of more than twelve months. Together with recent related amendments to GAAP, ASU 2016–02 represents ASC Topic 842 *Leases*, or "ASC Topic 842, which supersedes all current GAAP with respect to leases. Consistent with current GAAP, the recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. ASC Topic 842 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. The effective date of ASC Topic 842 is January 1, 2019, with early adoption permitted.

ASC Topic 842 will be applicable to our existing leases for office facilities and certain office equipment, vehicles and certain field equipment, land easements and similar arrangements for rights-of-way and potentially to certain drilling rig and completion contracts with terms in excess of 12 months to the extent we may have such contracts in the future. In addition, we believe that our crude oil and natural gas gathering commitment arrangements, as described in Note 13, include provisions that could be construed as leases. Our crude oil and natural gas gathering arrangements are fairly complex and include, among other provisions, multiple elements and term lengths, certain volumetric-based minimums and varying degrees of optionality available to both us and the service providers. Furthermore, these arrangements have certain material payment terms that are variable in nature which, depending upon the outcome of our analysis and resulting conclusions, could have a significant impact on the amounts recognized as right of use assets and corresponding lease liabilities. We anticipate that the adoption of ASC Topic 842 may significantly increase our total assets and liabilities. Accordingly, we are continuing to evaluate the effect that ASC Topic 842 will have on our Consolidated Financial Statements and related disclosures. We plan adopt ASC Topic 842 on the effective date in 2019 using the optional transition method and will recognize a cumulative-effect adjustment to the opening balance of retained earnings. We are also continuing to monitor developments regarding ASC Topic 842 that are unique to our industry.

Item 3. *Quantitative and Qualitative Disclosures About Market Risk.*

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and commodity price risk.

Interest Rate Risk

All of our long-term debt instruments are subject to variable interest rates. As of June 30, 2018, we had borrowings of $243.5 million and $200 million under the Credit Facility and Second Lien Facility at interest rates of 5.58% and 9.10%, respectively. Assuming a constant borrowing level under the Credit Facility and Second Lien Facility, an increase (decrease) in the interest rate of one percent would result in an increase (decrease) in interest payments of approximately $4 million on an annual basis.

Commodity Price Risk

We produce and sell crude oil, NGLs and natural gas. As a result, our financial results are affected when prices for these commodities fluctuate. Our price risk management programs permit the utilization of derivative financial instruments (such as swaps) to seek to mitigate the price risks associated with fluctuations in commodity prices as they relate to a portion of our anticipated production. The derivative instruments are placed with major financial institutions that we believe to be of acceptable credit risk. The fair values of our derivative instruments are significantly affected by fluctuations in the prices of crude oil. We have not typically entered into derivative instruments with respect to NGLs, although we may do so in the future.

As of June 30, 2018, our commodity derivative portfolio was in a net liabilities position. The contracts associated with this position are with eight counterparties, all of which are investment grade financial institutions. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions.

During the six months ended June 30, 2018, we reported net commodity derivative loss of $71.0 million. We have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of our derivative instruments. Our results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in crude oil, NGL and natural gas prices. These fluctuations could be significant in a volatile pricing environment. See Note 6 to the Condensed Consolidated Financial Statements for a further description of our price risk management activities.

The following table sets forth our commodity derivative positions as of June 30, 2018:

	Instrument	Average Volume Per Day		Weighted Average Price	Fair Value			
					Asset		Liability	
Crude Oil:		**(barrels)**		**($/barrel)**				
Third quarter 2018	Swaps-WTI	10,455	$	57.05	$	—	$	14,270
Third quarter 2018	Swaps-LLS	6,000	$	65.27		—		5,605
Fourth quarter 2018	Swaps-WTI	10,455	$	57.05		—		11,332
Fourth quarter 2018	Swaps-LLS	6,000	$	65.27		—		4,418
First quarter 2019	Swaps-WTI	6,446	$	54.46		—		6,999
First quarter 2019	Swaps-LLS	5,000	$	59.17		—		5,310
Second quarter 2019	Swaps-WTI	6,421	$	54.48		—		6,115
Second quarter 2019	Swaps-LLS	5,000	$	59.17		—		4,568
Third quarter 2019	Swaps-WTI	6,397	$	54.50		—		5,337
Third quarter 2019	Swaps-LLS	5,000	$	59.17		—		3,876
Fourth quarter 2019	Swaps-WTI	6,398	$	54.50		—		4,635
Fourth quarter 2019	Swaps-LLS	5,000	$	59.17		—		3,221
First quarter 2020	Swaps-WTI	6,000	$	54.09		—		3,846
Second quarter 2020	Swaps-WTI	6,000	$	54.09		—		3,302
Third quarter 2020	Swaps-WTI	6,000	$	54.09		—		2,844
Fourth quarter 2020	Swaps-WTI	6,000	$	54.09		—		2,451
Settlements to be paid in subsequent period								4,607

The following table illustrates the estimated impact on the fair values of our derivative financial instruments and operating income attributable to hypothetical changes in the underlying commodity prices. This illustration assumes that crude oil prices, natural gas prices and production volumes remain constant at anticipated levels. The estimated changes in operating income exclude potential cash receipts or payments in settling these derivative positions.

	Change of $10.00 per Bbl of Crude Oil or $1.00 per MMBtu of Natural Gas ($ in millions)			
		Increase		Decrease
Effect on the fair value of crude oil derivatives [1]	$	(97.0)	$	85.8
Effect of crude oil price changes for the remainder of 2018 on operating income, excluding derivatives [2]	$	19.3	$	(19.3)
Effect of natural gas price changes for the remainder of 2018 on operating income [2]	$	2.8	$	(2.8)

[1] Based on derivatives outstanding as of June 30, 2018.

[2] These sensitivities are subject to significant change.

Item 4. *Controls and Procedures.*

(a) Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of June 30, 2018. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported on a timely basis and that such information is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of June 30, 2018, such disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

During the three months ended June 30, 2018, no changes were made in our internal control over financial reporting 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.***

On May 12, 2016, we and eight of our subsidiaries filed voluntary petitions (*In re Penn Virginia Corporation, et al. Case No. 16-32395*) seeking relief under the Bankruptcy Code in the United States Bankruptcy Court for the Eastern District of Virginia, or the Bankruptcy Court.

On August 11, 2016, the Bankruptcy Court confirmed our Second Amended Joint Chapter 11 Plan of Reorganization of Penn Virginia Corporation and its Debtor Affiliates and we subsequently emerged from bankruptcy on September 12, 2016. See Note 4 to our Condensed Consolidated Financial Statements included in Part I, Item 1, “Financial Statements,” for a more detailed discussion of our bankruptcy proceedings.

We are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject. See Note 13 to our Condensed Consolidated Financial Statements included in Part I, Item 1, “Financial Statements” for additional information regarding our legal and regulatory matters.

Item 1A. ***Risk Factors.***

There have been no material changes to the risk factors disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2017.

Item 6. ***Exhibits.***

(31.1) *	Certification Pursuant to Rule 13a-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2) *	Certification Pursuant to Rule 13a-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1) †	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(32.2) †	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(101.INS) *	XBRL Instance Document
(101.SCH) *	XBRL Taxonomy Extension Schema Document
(101.CAL) *	XBRL Taxonomy Extension Calculation Linkbase Document
(101.DEF) *	XBRL Taxonomy Extension Definition Linkbase Document
(101.LAB) *	XBRL Taxonomy Extension Label Linkbase Document
(101.PRE) *	XBRL Taxonomy Extension Presentation Linkbase Document

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* Filed herewith.

† Furnished herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PENN VIRGINIA CORPORATION

August 8, 2018	By:	/s/ STEVEN A. HARTMAN
		Steven A. Hartman
		Senior Vice President, Chief Financial Officer and Treasurer
		(Principal Financial Officer)
August 8, 2018	By:	/s/ TAMMY L. HINKLE
		Tammy L. Hinkle
		Vice President and Controller
		(Principal Accounting Officer)

Exhibit 31.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John A. Brooks, President and Chief Executive Officer of Penn Virginia Corporation (the “Registrant”), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Registrant (this “Report”);

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Registrant’s disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

   (d) Disclosed in this Report any change in the Registrant’s internal control over financial reporting that occurred during the Registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and

5. The Registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant’s auditors and the audit committee of the Registrant’s board of directors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant’s internal control over financial reporting.

Date: August 8, 2018

/s/ JOHN A. BROOKS

John A. Brooks
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Steven A. Hartman, Senior Vice President, Chief Financial Officer and Treasurer of Penn Virginia Corporation (the “Registrant”), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Registrant (this “Report”);

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Registrant’s disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

   (d) Disclosed in this Report any change in the Registrant’s internal control over financial reporting that occurred during the Registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and

5. The Registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant’s auditors and the audit committee of the Registrant’s board of directors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant’s internal control over financial reporting.

Date: August 8, 2018

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Penn Virginia Corporation (the “Company”) on Form 10-Q for the six months ended June 30, 2018, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, John A. Brooks, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 8, 2018

/s/ JOHN A. BROOKS

John A. Brooks
President and Chief Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Penn Virginia Corporation (the “Company”) on Form 10-Q for the six months ended June 30, 2018, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Steven A. Hartman, Senior Vice President, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 8, 2018

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President, Chief Financial Officer and Treasurer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.