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 September 30, 2018

or

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

For the transition period from ______ to ______

Commission file number: 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)

16285 PARK TEN PLACE, SUITE 500
HOUSTON, TX 77084
(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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company," in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐	Smaller reporting company	☐
		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 November 2, 2018, 15,073,776 shares of common stock of the registrant were outstanding.

PENN VIRGINIA CORPORATION
QUARTERLY REPORT ON FORM 10-Q

For the Quarterly Period Ended September 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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Revenues				
Crude oil	$ 117,059	$ 29,963	$ 290,033	$ 92,387
Natural gas liquids	5,976	2,393	14,455	6,738
Natural gas	3,768	1,977	10,470	6,200
Gain (loss) on sales of assets, net	2	9	81	(60)
Other revenues, net	380	117	937	462
Total revenues	127,185	34,459	315,976	105,727
Operating expenses				
Lease operating	9,898	5,254	25,924	15,540
Gathering, processing and transportation	4,928	2,399	12,861	7,505
Production and ad valorem taxes	7,152	1,668	17,039	5,766
General and administrative	6,155	6,932	17,948	14,741
Depreciation, depletion and amortization	35,016	10,659	88,370	31,545
Total operating expenses	63,149	26,912	162,142	75,097
Operating income	64,036	7,547	153,834	30,630
Other income (expense)				
Interest expense	(7,322)	(1,202)	(18,073)	(3,014)
Derivatives	(40,689)	(12,275)	(111,725)	15,802
Other, net	241	(17)	167	45
Income (loss) before income taxes	16,266	(5,947)	24,203	43,463
Income tax benefit (expense)	10	—	(153)	—
Net income (loss)	$ 16,276	$ (5,947)	$ 24,050	$ 43,463
Net income (loss) per share:				
Basic	$ 1.08	$ (0.40)	$ 1.60	$ 2.90
Diluted	$ 1.06	$ (0.40)	$ 1.57	$ 2.89
Weighted average shares outstanding – basic	15,062	14,994	15,054	14,993
Weighted average shares outstanding – diluted	15,344	14,994	15,278	15,062

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
Net income (loss)	$ 16,276	$ (5,947)	$ 24,050	$ 43,463
Other comprehensive income:				
Change in pension and postretirement obligations, net of tax of $0 and $0 in 2018 and 2017, respectively	—	—	—	—
	—	—	—	—
Comprehensive income (loss)	$ 16,276	$ (5,947)	$ 24,050	$ 43,463

See accompanying notes to condensed consolidated financial statements.

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

	September 30, 2018	December 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$ 8,011	$ 11,017
Accounts receivable, net of allowance for doubtful accounts	72,045	69,821
Other current assets	7,446	6,250
Total current assets	87,502	87,088
Property and equipment, net (full cost method)	858,766	529,059
Deferred income taxes	4,790	4,943
Other assets	2,578	8,507
Total assets	$ 953,636	$ 629,597
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 111,962	$ 96,181
Derivative liabilities	80,641	27,777
Total current liabilities	192,603	123,958
Other liabilities	5,211	4,833
Derivative liabilities	37,570	13,900
Long-term debt, net	472,344	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; 15,073,776 and 15,018,870 shares issued as of September 30, 2018 and December 31, 2017, respectively	151	150
Paid-in capital	197,000	194,123
Retained earnings	48,757	27,366
Accumulated other comprehensive income	—	—
Total shareholders' equity	245,908	221,639
Total liabilities and shareholders' equity	$ 953,636	$ 629,597

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30,	
	2018	2017
Cash flows from operating activities		
Net income	$ 24,050	$ 43,463
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	88,370	31,545
Derivative contracts:		
Net losses (gains)	111,725	(15,802)
Cash settlements, net	(35,191)	(1,670)
Deferred income tax expense	153	—
(Gain) loss on sales of assets, net	(81)	60
Non-cash interest expense	2,509	1,362
Share-based compensation (equity-classified)	3,472	2,707
Other, net	38	59
Changes in operating assets and liabilities, net	(2,140)	(11,430)
Net cash provided by operating activities	192,905	50,294
Cash flows from investing activities		
Acquisitions, net	(85,387)	(200,162)
Capital expenditures	(323,259)	(67,844)
Proceeds from sales of assets, net	7,989	—
Net cash used in investing activities	(400,657)	(268,006)
Cash flows from financing activities		
Proceeds from credit facility borrowings	205,500	39,000
Repayment of credit facility borrowings	—	(7,000)
Proceeds from second lien facility, net	—	196,000
Debt issuance costs paid	(754)	(9,562)
Proceeds received from rights offering, net	—	55
Other, net	—	(55)
Net cash provided by financing activities	204,746	218,438
Net (decrease) increase in cash and cash equivalents	(3,006)	726
Cash and cash equivalents – beginning of period	11,017	6,761
Cash and cash equivalents – end of period	$ 8,011	$ 7,487
Supplemental disclosures:		
Cash paid for:		
Interest, net of amounts capitalized	$ 15,174	$ 1,596
Reorganization items, net	$ 514	$ 1,098
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	$ 1,833	$ 8,140
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.

On October 28, 2018, Denbury Resources Inc. ("Denbury") and Penn Virginia announced that they entered into a definitive merger agreement (the "Merger Agreement") pursuant to which Denbury will acquire Penn Virginia in a transaction valued at approximately $1.7 billion, including the assumption of debt (the "Merger"). The consideration to be paid to Penn Virginia shareholders will consist of 12.4 shares of Denbury common stock and $25.86 of cash for each share of Penn Virginia common stock. Penn Virginia shareholders will be permitted to elect to receive either all cash, all stock or a mix of stock and cash, in each case subject to proration, which will result in the aggregate issuance by Denbury of approximately 191.667 million Denbury shares and payment by Denbury of $400 million in cash. The transaction was unanimously approved by the board of directors of each company, and certain Penn Virginia shareholders holding approximately 15 percent of the outstanding shares signed voting agreements to vote "for" the transaction. The transaction, which is expected to close in the first quarter of 2019, is subject to the approval by the holders of more than two-thirds of the outstanding Company common shares, the approval by the holders of a majority of the outstanding Denbury common shares of an amendment to the certificate of incorporation to increase the number of authorized Denbury common shares, and the approval of the issuance of Denbury common shares in the Merger by the holders of a majority of the Denbury common shares represented in person or by proxy at a meeting of Denbury shareholders held to vote on such matter. The transaction is also conditioned on clearance under the Hart-Scott Rodino Act, and other customary closing conditions. The Merger Agreement contains certain termination rights for both Denbury and the Company, including if the Merger is not consummated by April 30, 2019, and provides for the payment of termination fees in certain circumstances.

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 nine months ended September 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 Statements of Operations for each of the three and nine months ended September 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, may have a significant impact on the amounts recognized as right of use assets and corresponding lease liabilities.

We are in the final stages of our review of leasing arrangements within the context of ASC Topic 842 in which we expect to: (i) conclude our assessment of applicability to our more complex arrangements, including the aforementioned gathering agreements, (ii) implement our enhanced lease accounting processes, (iii) implement changes to our internal controls to support the accounting and disclosure of leasing activities and (iv) assess the utilization of certain practical expedients provided in ASC Topic 842. 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 Merger Agreement as disclosed in Note 1 and an amendment to our credit agreement ("Credit Facility") as disclosed in Note 8, 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 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		
Revenue suspense		1,448
Asset retirement obligations		356
Net assets acquired	$	96,978
Cash consideration paid to Hunt, net	$	82,955
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	$	96,978

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 nine months ended September 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 September 30,				**Nine Months Ended September 30,**			
	2018		**2017**		**2018**		**2017**	
Total revenues	$	127,185	$	48,174	$	321,221	$	147,873
Net income (loss)	$	16,276	$	(6,939)	$	27,144	$	44,051
Net income (loss) per share - basic	$	1.08	$	(0.46)	$	1.80	$	2.94
Net income (loss) per share - diluted	$	1.06	$	(0.46)	$	1.78	$	2.92

Divestitures

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. The sale has an effective date of March 1, 2018 and closed on July 31, 2018, and we received proceeds of $6.2 million. The sale proceeds and de-recognition of certain assets and liabilities were recorded as a reduction of our net oil and gas properties. In November 2018, we paid $0.5 million, including $0.2 million of suspended revenues, to the buyer in connection with the final settlement.

The Mid-Continent properties had asset retirement obligations ("AROs") of $0.3 million as well as a net working capital deficit attributable to the oil and gas properties of $1.3 million as of July 31, 2018. The net pre-tax operating income attributable to the Mid-Continent assets was $0.2 million and $0.9 million for the three months ended September 30, 2018 and 2017, and $1.6 million and $1.5 million for the nine months ended September 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").

While our emergence from bankruptcy is complete, certain administrative and claims resolution activities have been ongoing under the authority of the Bankruptcy Court. The conclusion of the case will be denoted by the entry of a final decree and an order closing the case. As of November 2, 2018, all claims have effectively been resolved or are being administered outside of the bankruptcy and a final distribution for unsecured claims will be made upon the entry of the final decree. While most of these are matters for which shares of our common stock have been allocated, certain of these matters must be settled with cash payments. A hearing to address a proposed final decree and closing of the case has been scheduled for November 14, 2018. As of September 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:

	September 30, 2018	December 31, 2017
Customers	$ 64,965	$ 39,106
Joint interest partners	8,789	32,493
Other	532	584
	74,286	72,183
Less: Allowance for doubtful accounts	(2,241)	(2,362)
	$ 72,045	$ 69,821

For the nine months ended September 30, 2018, three customers accounted for $254.5 million, or approximately 81%, of our consolidated product revenues. The revenues generated from these customers during the nine months ended September 30, 2018, were $126.6 million, $65.9 million and $62.0 million, or 40%, 21% and 20% of the consolidated total, respectively. As of September 30, 2018 and December 31, 2017, $32.9 million and $32.1 million, or approximately 51% 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 nine months ended September 30, 2017, two customers accounted for $85.9 million, or approximately 82%, 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 nine months ended September 30, 2018:

	Three Months Ended September 30, 2018		
	As Determined Under Prior GAAP	As Reported Under ASC Topic 606	Increase (Decrease)
Revenues			
Crude oil	$ 117,059	$ 117,059	$ —
Natural gas liquids	$ 6,530	$ 5,976	$ (554)
Natural gas	$ 3,768	$ 3,768	$ —
Marketing services (included in Other revenues, net)	$ 143	$ 143	$ —
Operating expenses			
Gathering, processing and transportation	$ 5,482	$ 4,928	$ (554)
Net income	$ 16,276	$ 16,276	$ —

	Nine Months Ended September 30, 2018		
	As Determined Under Prior GAAP	As Reported Under ASC Topic 606	Increase (Decrease)
Revenues			
Crude oil	$ 290,033	$ 290,033	$ —
Natural gas liquids	$ 16,025	$ 14,455	$ (1,570)
Natural gas	$ 10,470	$ 10,470	$ —
Marketing services (included in Other revenues, net)	$ 388	$ 388	$ —
Operating expenses			
Gathering, processing and transportation	$ 14,431	$ 12,861	$ (1,570)
Net income	$ 24,050	$ 24,050	$ —

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 September 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”) and Louisiana Light Sweet (“LLS”) crude oil 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 September 30, 2018:

	Instrument	Average Volume Per Day	Weighted Average Price	Fair Value Asset	Fair Value Liability
Crude Oil:		(barrels)	($/barrel)		
Fourth quarter 2018	Swaps-WTI	10,455	$ 57.05	$ —	$ 15,125
Fourth quarter 2018	Swaps-LLS	6,000	$ 65.27	—	8,128
First quarter 2019	Swaps-WTI	6,446	$ 54.46	—	9,948
First quarter 2019	Swaps-LLS	5,000	$ 59.17	—	8,386
Second quarter 2019	Swaps-WTI	6,421	$ 54.48	—	9,413
Second quarter 2019	Swaps-LLS	5,000	$ 59.17	—	7,717
Third quarter 2019	Swaps-WTI	6,397	$ 54.50	—	8,722
Third quarter 2019	Swaps-LLS	5,000	$ 59.17	—	6,874
Fourth quarter 2019	Swaps-WTI	6,398	$ 54.50	—	7,925
Fourth quarter 2019	Swaps-LLS	5,000	$ 59.17	—	6,057
First quarter 2020	Swaps-WTI	6,000	$ 54.09	—	6,786
Second quarter 2020	Swaps-WTI	6,000	$ 54.09	—	6,142
Third quarter 2020	Swaps-WTI	6,000	$ 54.09	—	5,593
Fourth quarter 2020	Swaps-WTI	6,000	$ 54.09	—	5,068
Settlements to be paid in subsequent period					6,327

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 September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Derivative (losses) gains	$ (40,689)	$ (12,275)	$ (111,725)	$ 15,802

The effects of derivative gains and (losses) and cash settlements are reported as adjustments to reconcile net income (loss) 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	September 30, 2018 Derivative Liabilities	December 31, 2017 Derivative Liabilities
Commodity contracts	Derivative assets/liabilities – current	$ 80,641	$ 27,777
Commodity contracts	Derivative assets/liabilities – noncurrent	37,570	13,900
		$ 118,211	$ 41,677

As of September 30, 2018, we reported net commodity derivative liabilities of $118.2 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:

	September 30, 2018	December 31, 2017
Oil and gas properties:		
Proved	$ 864,426	$ 460,029
Unproved	132,576	117,634
Total oil and gas properties	997,002	577,663
Other property and equipment	18,701	12,712
Total properties and equipment	1,015,703	590,375
Accumulated depreciation, depletion and amortization	(156,937)	(61,316)
	$ 858,766	$ 529,059

Unproved property costs of $132.6 million and $117.6 million have been excluded from amortization as of September 30, 2018 and December 31, 2017, respectively. An additional $18.7 million of costs, associated with wells in-progress for which we had not previously recognized any proved undeveloped reserves, were excluded from amortization as of September 30, 2018. We transferred $11.4 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 nine months ended September 30, 2018. We capitalized internal costs of $2.4 million and $1.6 million and interest of $7.1 million and $0.1 million during the nine months ended September 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 $15.83 and $11.93 for the nine months ended September 30, 2018 and 2017, respectively.

8. Long-Term Debt

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

	September 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	$ 282,500		$ 77,000	
Second lien term loan	200,000	$ 10,156	200,000	$ 11,733
Totals	482,500	$ 10,156	277,000	$ 11,733
Less: Unamortized discount	(3,334)		(3,839)	
Less: Unamortized deferred issuance costs	(6,822)		(7,894)	
Long-term debt, net	$ 472,344		$ 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 which currently provides for a $450.0 million revolving commitment and borrowing base and a $5 million sublimit for the issuance of letters of credit. In October 2018, the borrowing base under the Credit Facility was increased from $340.0 million to $450.0 million pursuant to the Borrowing Base Agreement and Amendment No. 5 to the Credit Facility (the "Fifth Amendment"). In October 2018, we paid issuance costs of $0.3 million in connection with the Fifth Amendment for which amortization will begin in the fourth quarter of 2018. In the nine months ended September 30, 2018, we paid and capitalized issuance costs of $0.7 million in connection with the March 2018 amendment to the Credit Facility. 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 Credit Facility is available to us for general corporate purposes, including working capital. The Credit Facility matures in September 2020. We had $0.4 million and $0.8 million in letters of credit outstanding as of September 30, 2018 and December 31, 2017, respectively.

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 September 30, 2018, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 5.95%. 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 September 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 September 30, 2018, the actual interest rate of outstanding borrowings under the Second Lien Facility was 9.25%. 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 September 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. The deferred tax asset was reduced in connection with the 2018 income tax provisions as described below. We will continue to analyze the impacts of the TCJA on the Company and refine our estimates during the remainder of 2018.

We recognized a federal and state income tax expense for the nine months ended September 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 0.6%. The effect of the adjustment was to reduce our deferred tax asset to $4.8 million as of September 30, 2018. We recognized a federal income tax expense for the nine months ended September 30, 2017 at the blended rate of 35.5% 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 September 30, 2018. There were no interest and penalty charges recognized during the periods ended September 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 nine months ended September 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:

	September 30, 2018	December 31, 2017
Other current assets:		
Tubular inventory and well materials	$ 6,466	$ 5,146
Prepaid expenses	980	1,104
	$ 7,446	$ 6,250
Other assets:		
Deferred issuance costs of the Credit Facility	$ 2,578	$ 2,857
Deposit in escrow [1]	—	3,210
Other	—	2,440
	$ 2,578	$ 8,507
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 20,256	$ 22,579
Drilling costs	24,222	22,389
Royalties and revenue – related	51,542	39,287
Production, ad valorem and other taxes [2]	5,157	1,275
Compensation – related	4,369	2,975
Interest	613	223
Reserve for bankruptcy claims	3,940	3,933
Other [2]	1,863	3,520
	$ 111,962	$ 96,181
Other liabilities:		
Asset retirement obligations	$ 3,811	$ 3,286
Defined benefit pension obligations	880	971
Postretirement health care benefit obligations	520	476
Other	—	100
	$ 5,211	$ 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.

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 September 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:

	September 30, 2018			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Liabilities:				
Commodity derivative liabilities – current	$ (80,641)	$ —	$ (80,641)	$ —
Commodity derivative liabilities – noncurrent	$ (37,570)	$ —	$ (37,570)	$ —

	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 nine months ended September 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 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: $2.7 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

As of September 30, 2018, we had contractual commitments with fixed terms for two drilling rigs expiring in November 2018 and February 2019, respectively. Upon the expiration of their original terms, the drilling rig expiring in November 2018 and a third drilling rig that expired in September 2018 were converted from fixed-term commitments to a pad-to-pad basis during November and October 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 $12.3 million of combined obligations associated with these commitments. In May 2018, we committed to a five-year lease for new corporate office facilities that began in August 2018. The minimum lease commitments are as follows: less than $0.1 million for 2018, $0.4 million for 2019, $0.7 million for 2020, $0.7 million for 2021, $0.7 million for 2022, $0.7 million for 2023 and $0.2 million for 2024.

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. During the nine months ended September 30, 2018, we eliminated a $0.1 million reserve for a litigation matter. As of September 30, 2018, we had AROs of approximately $3.8 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 three and nine months ended September 30, 2018 and 2017.

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as of December 31, 2017	$ 150	$ 194,123	$ 27,366	$ —	$ 221,639
Net income	—	—	10,295	—	10,295
All other changes [1]	1	988	(2,659)	—	(1,670)
Balance as of March 31, 2018	$ 151	$ 195,111	$ 35,002	$ —	$ 230,264
Net loss	—	—	(2,521)	—	(2,521)
All other changes [1]	—	869	—	—	869
Balance as of June 30, 2018	$ 151	$ 195,980	$ 32,481	$ —	$ 228,612
Net income	—	—	16,276	—	16,276
All other changes [1]	—	1,020	—	—	1,020
Balance as of September 30, 2018	$ 151	$ 197,000	$ 48,757	$ —	$ 245,908

[1] Includes equity-classified share-based compensation of $3.5 million during the nine months ended September 30, 2018 . During the nine months ended September 30, 2018, 53,411 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).

	Common Stock		Paid-in Capital		Retained Earnings/(Accumulated Deficit)		Accumulated Other Comprehensive Income		Total Shareholders' Equity	
Balance as of December 31, 2016	$	150	$	190,621	$	(5,296)	$	73	$	185,548
Net income		—		—		28,081		—		28,081
All other changes [1]		—		835		—		—		835
Balance as of March 31, 2017	$	150	$	191,456	$	22,785	$	73	$	214,464
Net income		—		—		21,329		—		21,329
All other changes [1]		—		903		—		—		903
Balance as of June 30, 2017	$	150	$	192,359	$	44,114	$	73	$	236,696
Net loss		—		—		(5,947)		—		(5,947)
All other changes [1]		—		1,013		—		—		1,013
Balance as of September 30, 2017	$	150	$	193,372	$	38,167	$	73	$	231,762

[1] Includes equity-classified share-based compensation of $2.7 million during the nine months ended September 30, 2017 and $0.1 million from the receipt in May 2017 of proceeds attributable to the rights offering in 2016 that had been held in escrow, net of costs to register our common stock. During the nine months ended September 30, 2017, 12,252 shares of common stock were issued in connection with vesting of certain RSUs, net of shares withheld for income taxes.

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 347,440 RSUs and 98,526 PRSUs have been granted to employees and directors as of September 30, 2018.

We recognized $1.0 million and $1.0 million and $3.5 million and $2.7 million of expense attributable to the RSUs and PRSUs for the three and nine months ended September 30, 2018 and 2017, respectively. Approximately $0.6 million of the expense for the nine months ended September 30, 2018 was attributable to the accelerated vesting of certain awards of our former Executive Chairman.

In the nine months ended September 30, 2018 and 2017, we granted 42,459 and 190,891 RSUs to certain employees and a new member of the board of directors with an average grant-date fair value of $65.96 and $48.70 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 nine months ended September 30, 2018, 53,411 shares vested, net of shares withheld for income taxes.

In the nine months ended September 30, 2017, we granted 98,526 PRSUs to members of our management. No PRSUs were granted during the nine months ended September 30, 2018. In the nine months ended September 30, 2018, 1,495 shares vested, net of shares withheld for income taxes. The 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 $0.1 million and $0.4 million of expense attributable to the 401(k) Plan for the three and nine months ended September 30, 2018, respectively, and $0.2 million and $0.3 million for the three and nine months ended September 30, 2017, respectively. The charges for the 401(k) Plan are recorded as a component of “G&A expenses” in our Condensed Consolidated Statements of Operation.

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 nine months ended September 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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Interest on borrowings and related fees	$ 8,897	$ 879	$ 22,675	$ 1,784
Accretion of original issue discount [1]	172	—	505	—
Amortization of debt issuance costs	693	374	2,004	1,362
Capitalized interest	(2,440)	(51)	(7,111)	(132)
	$ 7,322	$ 1,202	$ 18,073	$ 3,014

[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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net income (loss) - basic and diluted	$ 16,276	$ (5,947)	$ 24,050	$ 43,463
Weighted-average shares – basic	15,062	14,994	15,054	14,993
Effect of dilutive securities [1]	282	—	224	69
Weighted-average shares – diluted	15,344	14,994	15,278	15,062

[1] For the three months ended September 30, 2017, 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:

- all of the risks and uncertainties related to our announced merger with Denbury Resources Inc., including the risk that the conditions to the closing of the transaction are not satisfied and the additional risks discussed in Part II, Item 1A of this report;
- 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 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 Part II, Item 1A of this report and 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 September 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.

Merger with Denbury

On October 28, 2018, Denbury Resources Inc., or Denbury, and Penn Virginia announced that they entered into a definitive merger agreement, or the Merger Agreement, pursuant to which Denbury will acquire Penn Virginia in a transaction valued at approximately $1.7 billion, including the assumption of debt, or the Merger. The consideration to be paid to Penn Virginia shareholders will consist of 12.4 shares of Denbury common stock and $25.86 of cash for each share of Penn Virginia common stock. Penn Virginia shareholders will be permitted to elect to receive either all cash, all stock or a mix of stock and cash, in each case subject to proration, which will result in the aggregate issuance by Denbury of approximately 191.667 million Denbury shares and payment by Denbury of $400 million in cash. The transaction was unanimously approved by the board of directors of each company, and certain Penn Virginia shareholders holding approximately 15 percent of the outstanding shares signed voting agreements to vote "for" the transaction. The transaction, which is expected to close in the first quarter of 2019, is subject to the approval by the holders of more than two-thirds of the outstanding Company common shares, the approval by the holders of a majority of the outstanding Denbury common shares of an amendment to the certificate of incorporation to increase the number of authorized Denbury common shares, and the approval of the issuance of Denbury common shares in the Merger by the holders of a majority of the Denbury common shares represented in person or by proxy at a meeting of Denbury shareholders held to vote on such matter. The transaction is also conditioned on clearance under the Hart-Scott Rodino Act, and other customary closing conditions. The Merger Agreement contains certain termination rights for both Denbury and the Company, including if the Merger is not consummated by April 30, 2019, and requires payment of a termination fee in certain circumstances. More details regarding, and a copy of, the Merger Agreement can be found in our Current Report on Form 8-K filed with the SEC on October 29, 2018.

Industry Environment and Recent Operating and Financial Highlights

Crude oil prices continued in a steadily rising trend that began in the second half of 2017 throughout the nine months ended September 30, 2018. 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 services.

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 nine months ended September 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 September 30, 2018, with comparison to the three months ended June 30, 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 four percent to 2,108 thousand barrels of oil equivalent, or MBOE, from 2,020 MBOE due primarily to the timing of wells turned to sales, which included 10 gross (9.7 net) wells turned to sales in the third quarter of 2018 and the full quarter effect of nine gross (7.8 net) wells that were turned to sales late in the second quarter of 2018.
- Product revenues increased approximately 14 percent to $126.8 million from $111.2 million due primarily to nine percent higher crude oil volume and six percent higher crude oil prices. Higher NGL revenues were due to nine percent higher prices partially offset by one percent lower volume. Lower natural gas revenues were due to 18 percent lower volumes partially offset by 17 percent higher natural gas pricing.
- Production and lifting costs (consisting of Lease operating expenses, or LOE, and GPT) increased on an absolute basis to $14.8 million from $13.3 million, and increased on a per unit basis to $7.04 per barrel of oil equivalent, or BOE, from $6.58 per BOE due primarily to the increase in production volume as well as higher surface maintenance and higher water disposal costs.
- Production and ad valorem taxes increased on an absolute and per unit basis to $7.2 million and $3.39 per BOE from $5.8 million and $2.87 per BOE, respectively, due to higher production volume and higher crude oil and NGL pricing and higher estimates for ad valorem taxes.
- G&A expenses increased on an absolute and per unit basis to $6.2 million and $2.92 per BOE from $5.3 million and $2.63 per BOE, respectively, due primarily to salary and benefits and higher employee-related support costs in the third quarter as we expanded our employee base. In addition we incurred moving costs associated with the relocation of our corporate headquarters to a new office as well as certain cost associated with our review of strategic alternatives.
- Depreciation, depletion and amortization, or DD&A, increased on an absolute and per unit basis to $35.0 million and $16.61 per BOE from $31.3 million and $15.48 per BOE, respectively, due primarily to higher production volume and the effects of higher drilling and completion costs and the sale of reserves attributable to the Mid-Continent region.
- Operating income increased to $64.0 million from $55.9 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			Nine Months Ended	
	September 30,	June 30,	September 30,	September 30,	
	2018	2018	2017	2018	2017
Total production (MBOE)	2,108	2,020	864	5,581	2,644
Average daily production (BOEPD)	22,912	22,200	9,396	20,444	9,683
Crude oil production (MBbl)	1,633	1,498	627	4,259	1,920
Crude oil production as a percent of total	77%	74%	73%	76%	73%
Product revenues	$ 126,803	$ 111,161	$ 34,333	$ 314,958	$ 105,325
Crude oil revenues	$ 117,059	$ 101,716	$ 29,963	$ 290,033	$ 92,387
Crude oil revenues as a percent of total	92%	92%	87%	92%	88%
Realized prices:					
Crude oil ($ per Bbl)	$ 71.67	$ 67.89	$ 47.78	$ 68.10	$ 48.12
NGLs ($ per Bbl) [1]	$ 22.41	$ 20.54	$ 19.18	$ 20.64	$ 17.98
Natural gas ($ per Mcf)	$ 3.02	$ 2.58	$ 2.92	$ 2.80	$ 2.96
Aggregate ($ per BOE)	$ 60.16	$ 55.02	$ 39.72	$ 56.43	$ 39.84
Prices adjusted for derivatives:					
Crude oil ($ per Bbl)	$ 62.36	$ 59.61	$ 49.04	$ 59.84	$ 47.25
Aggregate ($ per BOE)	$ 52.94	$ 48.89	$ 40.63	$ 50.13	$ 39.21
Production and lifting costs:					
Lease operating ($ per BOE)	$ 4.70	$ 4.32	$ 6.08	$ 4.65	$ 5.88
Gathering, processing and transportation ($ per BOE) [1]	$ 2.34	$ 2.26	$ 2.78	$ 2.30	$ 2.84
Production and ad valorem taxes ($ per BOE)	$ 3.39	$ 2.87	$ 1.93	$ 3.05	$ 2.18
General and administrative ($ per BOE) [2]	$ 2.92	$ 2.63	$ 8.02	$ 3.22	$ 5.58
Depreciation, depletion and amortization ($ per BOE)	$ 16.61	$ 15.48	$ 12.34	$ 15.83	$ 11.93
Capital expenditure program costs [3]	$ 104,589	$ 125,035	$ 29,366	$ 313,852	$ 74,162
Cash provided by operating activities [4]	$ 72,487	$ 81,736	$ 14,277	$ 192,905	$ 50,294
Cash paid for capital expenditures [5]	$ 121,909	$ 123,511	$ 24,261	$ 323,259	$ 67,844
Cash and cash equivalents at end of period	$ 8,011	$ 11,521	$ 7,487	$ 8,011	$ 7,487
Debt outstanding at end of period, net	$ 472,344	$ 432,824	$ 245,055	$ 472,344	$ 245,055
Credit available under credit facility at end of period	$ 57,100	$ 95,745	$ 179,745	$ 57,100	$ 179,745
Net development wells drilled and completed	9.7	16.9	5.0	36.6	11.6

[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 $16.48 and $15.26 per BOE and GPT of $2.38 and $2.45 per BOE for the three and nine months ended September 30, 2017 , respectively.

[2] Includes combined amounts of $0.51, $0.46 and $2.91 per BOE for the three months ended September 30, 2018, June 30, 2018 and September 30, 2017, respectively, and $0.77 and $1.59 per BOE for the nine months ended September 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 $15.2 million and $12.4 million for the three months ended September 30, 2018 and June 30, 2018, cash receipts from derivative settlements of $0.8 million for the three months ended September 30, 2017, respectively, and cash paid for derivative settlements of$35.2 million and $1.7 million for the nine months ended September 30, 2018 and 2017, respectively. Reflects changes in operating assets and liabilities of $(6.1) million, $11.4 million and $(4.9) million for the three months ended September 30, 2018 , June 30, 2018 and September 30, 2017, respectively, and $(2.1) million and $(11.4) million for the nine months ended September 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:

Evaluation of Strategic Alternatives and Merger with Denbury

On July 23, 2018, we announced that the Board of Directors intended to evaluate a range of strategic alternatives to enhance shareholder value. As described above under *Merger with Denbury*, we entered into the Merger Agreement with Denbury on October 28, 2018.

Production and Development Plans

Total production for the third quarter of 2018 was 2,108 MBOE, or 22,912 barrels of oil equivalent per day, or BOEPD, with approximately 77 percent, or 1,633 MBOE, of production from crude oil, 13 percent from NGLs and 10 percent from natural gas. Production from our Eagle Ford operations during this period was 2,081 MBOE or 22,622 BOEPD. Approximately 78 percent of our Eagle Ford production for the period was from crude oil, 12 percent was from NGLs and 10 percent was from natural gas. Production from our Eagle Ford operations was approximately 99 percent of total Company production during the third quarter of 2018.

We drilled and turned 10 gross (9.7 net) Eagle Ford wells to sales during the third quarter of 2018. Subsequent to September 30, 2018, we drilled and turned an additional five gross (4.3 net) wells to sales. As of November 2, 2018, we were drilling six gross (5.5 net) wells with our three operated drilling rigs, five gross (4.7 net) wells were completing.

As of November 2, 2018, we had approximately 98,600 gross (84,700 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.

Amendment to Credit Facility

In October 2018, we entered into the Borrowing Base Agreement and Amendment No. 5 to the Credit Facility, or the Fifth Amendment, to our credit agreement, or Credit Facility, increasing the borrowing base from $340.0 million to $450.0 million, among other things.

Acquisition of Producing Properties

In December 2017, we entered into a purchase and sale agreement with Hunt Oil Company, or 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, or 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. We received $1.4 million from Hunt, primarily attributable to suspended revenues, in a final settlement that occurred in July 2018. 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 November 2, 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. The sale has an effective date of March 1, 2018, and closed on July 31, 2018, and we received proceeds of $6.2 million. In November 2018, we paid $0.5 million, including $0.2 million of suspended revenues, to the buyer in connection with the final settlement.

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 $450 million in borrowing commitments. The current borrowing base under the Credit Facility is also $450 million. As of November 2, 2018, we had $155.1 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 $405 million and $410 million for 2018 with approximately 97 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 November 2, 2018, we had approximately $8 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 nine-months ended September 30, 2018, we borrowed $39.0 million and $205.5 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 September 30, 2018	$ 268,783	$ 282,500	5.82%
Nine months ended September 30, 2018	$ 205,901	$ 282,500	5.52%

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:

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Cash flows from operating activities		
Operating cash flows, net of working capital changes	$ 244,591	$ 55,370
Crude oil derivative settlements paid, net	(35,191)	(1,670)
Interest payments, net of amounts capitalized	(15,174)	(1,596)
Acquisition, divestiture and strategic transaction costs paid	(557)	(712)
Bankruptcy-related administration fees and costs paid	(514)	(1,098)
Consulting costs paid to former Executive Chairman	(250)	—
Net cash provided by operating activities	192,905	50,294
Cash flows from investing activities		
Acquisitions, net	(85,387)	(200,162)
Capital expenditures	(323,259)	(67,844)
Proceeds from sales of assets, net	7,989	—
Net cash used in investing activities	(400,657)	(268,006)
Cash flows from financing activities		
Proceeds from credit facility borrowings, net	205,500	32,000
Proceeds from second lien facility, net	—	196,000
Debt issuance costs paid	(754)	(9,562)
Proceeds received from rights offering, net	—	55
Other, net	—	(55)
Net cash provided by financing activities	204,746	218,438
Net (decrease) increase in cash and cash equivalents	$ (3,006)	$ 726

Cash Flows from Operating Activities. The increase in net cash from operating activities for the nine months ended September 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 acquisition, divestiture and strategic transaction costs as well as lower bankruptcy-related administration costs. These items were partially offset by: (i) substantially higher settlements paid for crude oil derivatives, (ii) higher interest payments due to greater outstanding borrowings in the 2018 period and (iii) 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 $86.5 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 $8.0 million in the 2018 period attributable to the sales of: (i) all of our Mid-Continent properties, (ii) undeveloped acreage holdings in the Tuscaloosa Marine Shale in Louisiana, (iii) certain undeveloped deep leasehold rights in Oklahoma, (iv) certain pipeline assets in our former Marcellus Shale operating region and (v) scrap tubular and well materials.

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

	Nine Months Ended	
	September 30, 2018	September 30, 2017
Drilling and completion	$ 302,888	$ 72,263
Lease acquisitions and other land-related costs	4,239	2,094
Pipeline, gathering facilities and other equipment, net	6,502	(703)
Geological and geophysical (seismic) costs	223	508
	$ 313,852	$ 74,162

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:

	Nine Months Ended	
	September 30, 2018	September 30, 2017
Total capital expenditures program costs (from above)	$ 313,852	$ 74,162
Increase in accrued capitalized costs	(1,833)	(8,140)
Less:		
Transfers from tubular inventory and well materials	(4,905)	(2,581)
Sales and use tax refunds received and applied to property accounts	(643)	—
Add:		
Tubular inventory and well materials purchased in advance of drilling	7,245	2,657
Capitalized internal labor	2,432	1,614
Capitalized interest	7,111	132
Total cash paid for capital expenditures	$ 323,259	$ 67,844

Cash Flows from Financing Activities. The 2018 period includes borrowings of $205.5 million under the Credit Facility, which were used to fund the three-rig capital program and the Hunt Acquisition, while the 2017 period only includes borrowings of $39 million and repayments of $7 million. In the 2017 period, we received proceeds of $196 million from the $200 million Second Lien Facility, or Second Lien Facility, net of a discount. 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 Second Lien Facility compared to $9.6 million paid in the 2017 period in connection with an amendments to the Credit Facility and the issuance of the Second Lien 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:

	September 30, 2018	December 31, 2017
Credit Facility borrowings	$ 282,500	$ 77,000
Second Lien Facility term loan, net	189,844	188,267
Total debt, net	472,344	265,267
Shareholders' equity	245,908	221,639
	$ 718,252	$ 486,906
Debt as a % of total capitalization	66%	54%

Credit Facility. The Credit Facility provides for a $450 million revolving commitment and borrowing base which was increased from $340 million pursuant to the Fifth Amendment as described above. 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 $0.4 million and $0.8 million in letters of credit outstanding as of September 30, 2018 and December 31, 2017, respectively.

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 September 30, 2018, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 5.95%. 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 September 30, 2018, the actual interest rate on the Second Lien Facility was 9.25%. 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 September 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
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
Crude oil (MBbl and BOPD)	1,633	627	1,006	17,753	6,816	10,937
NGLs (MBbl and BOPD)	267	125	142	2,899	1,356	1,543
Natural gas (MMcf and MMcfpd)	1,248	676	572	14	7	7
Total (MBOE and BOEPD)	2,108	864	1,243	22,912	9,396	13,516

	Three Months Ended		2018 vs. 2017	Three Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
	(MBOE)			(BOEPD)		
South Texas	2,081	785	1,296	22,622	8,535	14,087
Mid-Continent [1]	27	79	(53)	290	861	(571)
	2,108	864	1,243	22,912	9,396	13,516

	Nine Months Ended		2018 vs. 2017	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
Crude oil (MBbl and BOPD)	4,259	1,920	2,339	15,599	7,032	8,567
NGLs (MBbl and BOPD)	700	375	325	2,565	1,373	1,192
Natural gas (MMcf and MMcfpd)	3,734	2,094	1,640	14	8	6
Total (MBOE and BOEPD)	5,581	2,644	2,938	20,444	9,683	10,761

	Nine Months Ended		2018 vs. 2017	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
	(MBOE)			(BOE per day)		
South Texas	5,417	2,420	2,997	19,841	8,864	10,977
Mid-Continent [1]	165	224	(59)	603	819	(216)
	5,581	2,644	2,938	20,444	9,683	10,761

[1] Represents production through July 31, 2018.

Total production increased during the three and nine 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 the effect of the divestiture in July 2018 of our former Mid-Continent operations, as well as natural production declines from our legacy Eagle Ford wells.

Approximately 77 percent and 76 percent of total production during the three and nine month periods in 2018 was attributable to crude oil when compared to approximately 73 percent during each of the corresponding periods in 2017. Our Eagle Ford production represented 99 percent and 97 percent of our total production during the three and nine month periods in 2018 compared to approximately 91 percent and 92 percent from this region during the corresponding periods in 2017. Subsequent to the sale of our Mid-Continent properties on July 31, 2018, the entirety of our production was derived from the Eagle Ford. During the three and nine month periods in 2018, we turned 10 gross (9.7 net) and 43 gross (36.6 net) Eagle Ford wells to sales compared to seven gross (5.0 net) and 20 gross (11.6 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
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
				($ per unit of volume)		
Crude oil	$ 117,059	$ 29,963	$ 87,096	$ 71.67	$ 47.78	$ 23.89
NGLs	5,976	2,393	3,583	$ 22.41	$ 19.18	$ 3.23
Natural gas	3,768	1,977	1,791	$ 3.02	$ 2.92	$ 0.10
Total	$ 126,803	$ 34,333	$ 92,470	$ 60.16	$ 39.72	$ 20.44

	Three Months Ended		2018 vs. 2017	Three Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
				($ per BOE)		
South Texas	$ 126,168	$ 32,475	$ 93,693	$ 60.62	$ 41.36	$ 19.26
Mid-Continent [1]	635	1,858	(1,223)	$ 23.76	$ 23.45	$ 0.31
	$ 126,803	$ 34,333	$ 92,470	$ 60.16	$ 39.72	$ 20.44

	Nine Months Ended		2018 vs. 2017	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
				($ per unit of volume)		
Crude oil	$ 290,033	$ 92,387	$ 197,646	$ 68.10	$ 48.12	$ 19.98
NGLs	14,455	6,738	7,717	$ 20.64	$ 17.98	$ 2.66
Natural gas	10,470	6,200	4,270	$ 2.80	$ 2.96	$ (0.16)
Total	$ 314,958	$ 105,325	$ 209,633	$ 56.43	$ 39.84	$ 16.59

	Nine Months Ended		2018 vs. 2017	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
				($ per BOE)		
South Texas	$ 311,028	$ 100,078	$ 210,950	$ 57.42	$ 41.35	$ 16.07
Mid-Continent [1]	3,930	5,247	(1,317)	$ 23.87	$ 23.47	$ 0.40
	$ 314,958	$ 105,325	$ 209,633	$ 56.43	$ 39.84	$ 16.59

[1] Represents product revenues through July 31, 2018.

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

	Three Months Ended September 30, 2018 vs. 2017			Nine Months Ended September 30, 2018 vs. 2017		
	Revenue Variance Due to			Revenue Variance Due to		
	Volume	Price	Total	Volume	Price	Total
Crude oil	$ 48,078	$ 39,018	$ 87,096	$ 112,556	$ 85,090	197,646
NGLs	2,724	859	3,583	5,853	1,864	7,717
Natural gas	1,671	120	1,791	4,854	(584)	4,270
	$ 52,473	$ 39,997	$ 92,470	$ 123,263	$ 86,370	$ 209,633

Our product revenues during the three and nine month periods in 2018 increased over the corresponding periods in 2017 due primarily to approximately 160 percent and 122 percent higher crude oil volumes and 50 percent and 42 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 higher than the comparable WTI index during each of the three and nine month periods in 2018, respectively. Higher natural gas revenues were primarily attributable to higher production volumes which were partially offset by the effect of five percent lower natural gas pricing during the nine month period. Excluding the effects of the adoption of ASC Topic 606, or $0.6 million and $1.6 million, respectively, NGL pricing actually increased by 28 percent and 27 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 nine month periods in 2018 as compared to 87 percent and 88 percent during the three and nine month periods in 2017. Total Eagle Ford revenues were approximately 99 percent of total revenues for each of the three and nine month periods in 2018 and 95 percent for each of the corresponding periods in 2017. Effective August 2018, all of our revenues were derived from the Eagle Ford.

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	Nine Months Ended		2018 vs. 2017
	September 30,	September 30,	Favorable	September 30,	September 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Crude oil revenues, as reported	$ 117,059	$ 29,963	$ 87,096	$ 290,033	$ 92,387	$ 197,646
Derivative settlements, net	(15,214)	788	(16,002)	(35,191)	(1,670)	(33,521)
	$ 101,845	$ 30,751	$ 71,094	$ 254,842	$ 90,717	$ 164,125
Crude oil prices per Bbl	$ 71.67	$ 47.78	$ 23.89	$ 68.10	$ 48.12	$ 19.98
Derivative settlements per Bbl	(9.32)	1.26	(10.58)	(8.26)	(0.87)	(7.39)
	$ 62.36	$ 49.04	$ 13.31	$ 59.84	$ 47.25	$ 12.59

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	Nine Months Ended		2018 vs. 2017
	September 30,	September 30,	Favorable	September 30,	September 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Gain (loss) on sales of assets, net	$ 2	$ 9	$ (7)	$ 81	$ (60)	$ 141

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

Other Revenues, net

Other revenues, net, includes fees for marketing and water disposal 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	Nine Months Ended		2018 vs. 2017
	September 30,	September 30,	Favorable	September 30,	September 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Other revenues, net	$ 380	$ 117	$ 263	$ 937	$ 462	$ 475

Other revenues, net increased during the three and nine 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	Nine Months Ended		2018 vs. 2017
	September 30,	September 30,	Favorable	September 30,	September 30,	Favorable
	2018	2017	(Unfavorable)	2018	2017	(Unfavorable)
Lease operating	$ 9,898	$ 5,254	$ (4,644)	$ 25,924	$ 15,540	$ (10,384)
Per unit of production ($ per BOE)	$ 4.70	$ 6.08	$ 1.38	$ 4.65	$ 5.88	$ 1.23
% change per unit of production			22.7%			20.9%

LOE increased on an absolute basis, but declined on a per unit basis during the three and nine 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	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
Gathering, processing and transportation	$ 4,928	$ 2,399	$ (2,529)	$ 12,861	$ 7,505	$ (5,356)
Per unit of production ($ per BOE)	$ 2.34	$ 2.78	$ 0.44	$ 2.30	$ 2.84	$ 0.54
% change per unit of production			15.8%			19.0%

GPT expense increased on an absolute basis during the three and nine 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 $1.6 million, respectively. Per unit costs declined in the 2018 periods due primarily to the effect of the adoption of ASC Topic 606, or $0.26 and $0.28 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	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
Production and ad valorem taxes						
Production/severance taxes	$ 6,121	$ 1,643	$ (4,478)	$ 15,021	$ 4,996	$ (10,025)
Ad valorem taxes	1,031	25	(1,006)	2,018	770	(1,248)
	$ 7,152	$ 1,668	$ (5,484)	$ 17,039	$ 5,766	$ (11,273)
Per unit production ($ per BOE)	$ 3.39	$ 1.93	$ (1.46)	$ 3.05	$ 2.18	$ (0.87)
Production/severance tax rate as a percent of product revenue	4.8%	4.8%		4.8%	4.7%	

Production taxes increased on both an absolute and per unit basis during the three and nine 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	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
Primary G&A	$ 5,090	$ 4,414	$ (676)	$ 13,695	$ 10,549	$ (3,146)
Share-based compensation (equity-classified)	1,021	1,013	(8)	3,472	2,707	(765)
Significant special charges:						
Acquisition, divestiture and strategic transaction costs	44	1,505	1,461	531	1,505	974
Executive retirement costs	—	—	—	250	—	(250)
Restructuring expenses	—	—	—	—	(20)	(20)
Total G&A	$ 6,155	$ 6,932	$ 777	$ 17,948	$ 14,741	$ (3,207)
Per unit of production ($ per BOE)	$ 2.92	$ 8.02	$ 5.10	$ 3.22	$ 5.58	$ 2.36
Per unit of production excluding share-based compensation and other significant special charges identified above ($ per BOE)	$ 2.41	$ 5.11	$ 2.70	$ 2.45	$ 3.99	$ 1.54

Our primary G&A expenses increased on an absolute and decreased on a per unit basis during the three and nine 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 as well as costs associated with the relocation of our corporate headquarters to a new office. Higher production volume had the effect of reducing G&A per unit of production during the 2018 three and nine 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 nine 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 third quarter of 2018, we incurred consulting and other costs associated with our review of strategic alternatives. In addition to these costs, the nine month period of 2018 included transaction costs associated with the Mid-Continent divestiture and 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 nine 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	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
DD&A expense	$ 35,016	$ 10,659	$ (24,357)	$ 88,370	$ 31,545	$ (56,825)
DD&A Rate ($ per BOE)	$ 16.61	$ 12.34	$ (4.27)	$ 15.83	$ 11.93	$ (3.90)

DD&A increased on an absolute and per unit basis during the three and nine month periods ended in 2018 when compared to the corresponding periods in 2017. Higher production volume provided for an increase of approximately $15.4 million and $35.0 million while $9.0 million and $21.8 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, as well as the effect of the sale of reserves attributable to the Mid-Continent region in July 2018, 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	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
Interest on borrowings and related fees	$ 8,897	$ 879	$ (8,018)	$ 22,675	$ 1,784	$ (20,891)
Accretion of original issue discount	172	—	(172)	505	—	(505)
Amortization of debt issuance costs	693	374	(319)	2,004	1,362	(642)
Capitalized interest	(2,440)	(51)	2,389	(7,111)	(132)	6,979
	$ 7,322	$ 1,202	$ (6,120)	$ 18,073	$ 3,014	$ (15,059)

Interest expense increased during the three and nine 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	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
Crude oil derivative gains (losses)	$ (40,689)	$ (12,275)	$ (28,414)	$ (111,725)	$ 15,802	$ (127,527)

In the three and nine 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 $15.2 million and $35.2 million in the three and nine month periods in 2018 received cash settlements of $0.8 million and paid cash settlements of $1.7 million in the three and nine months ended September 30, 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	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
Other, net	$ 241	$ (17)	$ 258	$ 167	$ 45	$ 122

Other, net income (expense) increased during the three and nine month periods in 2018 as compared to the corresponding periods in 2017 due primarily to recoveries of joint interest receivable balances previously written-off in connection with the bankruptcy of a former partner and the reversal of a litigation reserve, partially offset by interest charges applicable to a settlement with a royalty owner. Each of the three and nine 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	Nine Months Ended		2018 vs. 2017
	September 30, 2018	September 30, 2017	Favorable (Unfavorable)	September 30, 2018	September 30, 2017	Favorable (Unfavorable)
Income tax benefit (expense)	$ 10	$ —	$ 10	$ (153)	$ —	$ (153)
Effective tax rate	(0.1)%	—%		0.6%	—%	

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 nine-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 nine 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 0.6%. The effect of the adjustment was to reduce our deferred tax asset to $4.8 million as of September 30, 2018. We recognized federal income tax benefits for the three and nine months ended September 30, 2017 at the blended rate of 35.5% 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 September 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, may have a significant impact on the amounts recognized as right of use assets and corresponding lease liabilities.

We are in the final stages of our review of leasing arrangements within the context of ASC Topic 842 in which we expect to: (i) conclude our assessment of applicability to our more complex arrangements, including the aforementioned gathering agreements, (ii) implement our enhanced lease accounting processes, (iii) implement changes to our internal controls to support the accounting and disclosure of leasing activities and (iv) assess the utilization of certain practical expedients provided in ASC Topic 842. 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.

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 September 30, 2018, we had borrowings of $282.5 million and $200 million under the Credit Facility and Second Lien Facility at interest rates of 5.95% and 9.25%, 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 $4.8 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 September 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 nine months ended September 30, 2018, we reported net commodity derivative loss of $111.7 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 September 30, 2018:

	Instrument	Average Volume Per Day	Weighted Average Price	Fair Value Asset	Fair Value Liability
Crude Oil:		(barrels)	($/barrel)		
Fourth quarter 2018	Swaps-WTI	10,455	$ 57.05	$ —	$ 15,125
Fourth quarter 2018	Swaps-LLS	6,000	$ 65.27	—	8,128
First quarter 2019	Swaps-WTI	6,446	$ 54.46	—	9,948
First quarter 2019	Swaps-LLS	5,000	$ 59.17	—	8,386
Second quarter 2019	Swaps-WTI	6,421	$ 54.48	—	9,413
Second quarter 2019	Swaps-LLS	5,000	$ 59.17	—	7,717
Third quarter 2019	Swaps-WTI	6,397	$ 54.50	—	8,722
Third quarter 2019	Swaps-LLS	5,000	$ 59.17	—	6,874
Fourth quarter 2019	Swaps-WTI	6,398	$ 54.50	—	7,925
Fourth quarter 2019	Swaps-LLS	5,000	$ 59.17	—	6,057
First quarter 2020	Swaps-WTI	6,000	$ 54.09	—	6,786
Second quarter 2020	Swaps-WTI	6,000	$ 54.09	—	6,142
Third quarter 2020	Swaps-WTI	6,000	$ 54.09	—	5,593
Fourth quarter 2020	Swaps-WTI	6,000	$ 54.09	—	5,068
Settlements to be paid in subsequent period					6,327

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]	$ (84.0)	$ 69.4
Effect of crude oil price changes for the remainder of 2018 on operating income, excluding derivatives [2]	$ 27.6	$ (27.6)
Effect of natural gas price changes for the remainder of 2018 on operating income [2]	$ 3.5	$ (3.5)

[1] Based on derivatives outstanding as of September 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 September 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 September 30, 2018, such disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

During the quarter ended September 30, 2018, there were no changes to 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, with the exception of the following :

There can be no assurance that the Merger will be consummated or that we will realize the anticipated benefits of the Merger.

There can be no assurance that the Merger will be consummated and our shareholders will receive the merger consideration. The completion of the Merger is subject to various closing conditions and termination rights (including if the Merger is not consummated by April 30, 2019). In addition to other conditions that are beyond our control, the Merger is subject to approval by the holders of more than two-thirds of the outstanding Company common shares, the approval by the holders of a majority of the outstanding Denbury common shares of an amendment to the certificate of incorporation to increase the number of authorized Denbury common shares, and the approval of the issuance of Denbury common shares in the Merger by the holders of a majority of the Denbury common shares represented in person or by proxy at a meeting of Denbury shareholders held to vote on such matter. We cannot guarantee that the closing conditions set forth in the Merger Agreement will be satisfied or, even if satisfied, that no event of termination will take place. The completion of the Merger is not assured and is subject to risks, including the risk that the approval of our shareholders or Denbury’s stockholders is not obtained. Activist shareholders may increase the risk that the requisite votes are not obtained. Further, the Merger may not be completed even if such approval is obtained. The Agreement contains conditions, some of which are beyond our control, that, if not satisfied or waived, may prevent, delay or otherwise result in the Merger not occurring. Even if we complete the Merger, the combined company may not realize the benefits and guidance provided by either Denbury or us, including due to factors beyond the control of the combined company’s management.

Because the exchange ratio in the Merger Agreement is fixed and because the market price of Denbury common stock will fluctuate prior to the completion of the Merger, our shareholders cannot be sure of the market value of the Denbury common stock they will receive as Merger consideration relative to the value of the cash and shares of common stock they exchange at the closing.

On October 28, 2018, we entered into the Merger Agreement with Denbury in a merger transaction pursuant to which Denbury would acquire Penn Virginia. Under the terms of the Merger Agreement, shareholders of Penn Virginia will receive the merger consideration, or the Merger Consideration, consisting of a combination of 12.4 shares of Denbury common stock and $25.86 of cash for each share of Penn Virginia common stock, subject to election of the Penn Virginia shareholders to receive either all cash, all stock or a mix of stock and cash, in each case subject to proration. Based on the closing price of Denbury common stock on October 26, 2018, the Merger Consideration represents consideration to each Penn Virginia shareholder of $79.80 per share. The exchange ratio for the Merger Consideration is fixed, and there will be no adjustment to the Merger Consideration for changes in the market price of Denbury’s common stock or our common stock prior to the completion of the Merger.

If the Merger is completed, there will be a time lapse between the date of signing of the Merger Agreement and the date on which our shareholders who are entitled to receive the Merger Consideration actually receive the Merger Consideration. The market value of shares of Denbury's common stock and our common stock may fluctuate during this period as a result of a variety of factors, including general market and economic conditions, changes in each company's business, operations and prospects, commodity prices, regulatory considerations, and the market's assessment of Denbury's business and the Merger. Such factors are difficult to predict and in many cases may be beyond the control of Denbury and us. The actual value of any Merger Consideration received by our shareholders at the completion of the Merger will depend on the market value of the shares of Denbury common stock at that time. This market value may differ, possibly materially, from the market value of shares of Denbury common stock at the time the Merger Agreement was entered into or at any other time. If the trading price of Denbury common stock at the closing of the Merger is less than the trading price of Denbury common stock on the date that the Merger Agreement was signed, particularly if the trading price of Penn Virginia's common stock increases, then the market value of the Merger consideration will be less than contemplated at the time the Merger Agreement was signed.

The Merger Agreement limits our ability to pursue alternatives to the Merger.

The Merger Agreement contains provisions that may discourage a third party from submitting a competing proposal that might result in greater value to our shareholders than the Merger, or may result in a potential competing acquirer of the Company proposing to pay a lower per share price to acquire the Company than it might otherwise have proposed to pay. These provisions include a general prohibition on us from soliciting or, subject to certain exceptions relating to the exercise of fiduciary duties by our board, entering into discussions with any third party regarding any competing proposal or offer for a competing transaction. Even upon termination of the Merger Agreement under certain circumstances relating to the exercise of fiduciary duties by our board, we may be required to pay Denbury fees and expenses, which may further deter counterparties to any potential alternative transaction.

Failure to complete the Merger could negatively impact the price of shares of our common stock, as well as our future businesses and financial results.

The Merger Agreement contains a number of conditions that must be satisfied or waived prior to the completion of the Merger. There can be no assurance that all of the conditions to the completion of the Merger will be so satisfied or waived. If these conditions are not satisfied or waived, we will be unable to complete the Merger.

If the Merger is not completed for any reason, including the failure to receive the required approval of our shareholders or Denbury's stockholders, our businesses and financial results may be adversely affected, including as follows:

- we may experience negative reactions from the financial markets, including negative impacts on the market price of our common stock;
- the manner in which customers, vendors, business partners and other third parties perceive the Company may be negatively impacted, which in turn could affect our marketing operations or our ability to compete for new business or obtain renewals in the marketplace more broadly;
- we may experience negative reactions from employees; and
- we will have expended time and resources that could otherwise have been spent on our existing businesses and the pursuit of other opportunities that could have been beneficial to the Company, and our ongoing business and financial results may be adversely affected.

In addition to the above risks, if the Merger Agreement is terminated and our board seeks an alternative transaction, our shareholders cannot be certain that we will be able to find a party willing to engage in a transaction on more attractive terms than the Merger. If the Merger Agreement is terminated under specified circumstances, we may be required to pay Denbury a $45 million termination fee.

We will be subject to business uncertainties while the Merger is pending, which could adversely affect our businesses.

Uncertainty about the effect of the Merger on employees and customers may have an adverse effect on the Company. These uncertainties may impair our ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter and could cause customers and others that deal with us to seek to change their existing business relationships with us. Employee retention at the Company may be particularly challenging during the pendency of the Merger, as employees may experience uncertainty about their roles. In addition, the Merger Agreement restricts us from entering into certain corporate transactions, changing our capital budget, incurring certain indebtedness and taking other specified actions without the consent of Denbury, and generally requires us to continue our operations in the ordinary course of business, until completion of the Merger. These restrictions may prevent us from pursuing attractive business opportunities or adjusting our capital plan prior to the completion of the Merger.

We will incur significant transaction and Merger-related costs in connection with the Merger, which may be in excess of those anticipated by us.

We have incurred and expect to continue to incur a number of non-recurring costs associated with negotiating and completing the Merger, obtaining shareholder approval (including responding to any activist shareholders) and, combining the operations of the two companies. These fees and costs have been, and will continue to be, substantial. The substantial majority of non-recurring expenses will consist of transaction costs related to the Merger and include, among others, employee retention costs, fees paid to financial, legal and accounting advisors, severance and benefit costs and filing fees. Many of these costs will be borne by us even if the Merger is not completed.

Completion of the Merger may trigger change in control or other provisions in certain agreements to which the Company is a party.

The completion of the Merger may trigger change in control or other provisions in certain agreements to which we are a party. If we are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under the agreements, potentially terminating the agreements or seeking monetary damages. Even if we are able to negotiate waivers, the counterparties may require a fee for such waivers or seek to renegotiate the agreements on terms less favorable to us.

We may be a target of securities class action and derivative lawsuits which could result in substantial costs and may delay or prevent the Merger from being completed.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into merger agreements. Even if the lawsuits are without merit, defending against these claims can result in substantial costs and divert management time and resources. An adverse judgment could result in monetary damages, which could have a negative impact on our liquidity and financial condition. Additionally, if a plaintiff is successful in obtaining an injunction prohibiting completion of the Merger, then that injunction may delay or prevent the Merger from being completed, which may adversely affect our and Denbury’s business, financial position and results of operation.

The parties must obtain certain regulatory approvals in order to complete the actions contemplated by the Merger Agreement; if such approvals are not obtained or are obtained with conditions, the Merger may be prevented or delayed or the anticipated benefits of the Merger could be reduced.

Consummation of the Merger is conditioned upon, among other things, the expiration or termination of the waiting period (and any extensions thereof) applicable to the Merger under the U.S. Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. At any time before or after the Merger is consummated, any of the U.S. Department of Justice, the Federal Trade Commission or U.S. state attorneys general could take action under the antitrust laws in opposition to the Merger, including seeking to enjoin completion of the Merger, condition completion of the Merger upon the divestiture of assets, or impose restrictions on post-merger operations. Any such requirements or restrictions may prevent or delay completion of the Merger or may reduce the anticipated benefits of the Merger. Additionally, Denbury has agreed to accept certain potential remedies, conditioned on the closing, and may take other actions that Denbury determines in its sole discretion to take, to the extent necessary to ensure satisfaction, on or prior to the termination date of the Merger Agreement (as it may be extended), of certain conditions to the closing of the Merger relating to regulatory approvals. There can be no assurance we will receive all regulatory approvals necessary to consummate the transaction on the timeline expected or at all.

Item 6. ***Exhibits.***

(2.1)	Agreement and Plan of Merger dated as of October 28, 2018, by and among Denbury Resources Inc, Dragon Merger Sub Inc, DR Sub LLC Sub and Penn Virginia Corporation (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on October 29, 2018).
(10.1)*	Second Amendment to Second Amended and Restated Construction and Field Gathering Agreement dated as of July 2, 2018 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas L.P.
(10.2) #	First Amendment to First Amended and Restated Crude Oil Marketing Agreement dated as of July 2, 2018 by and between Penn Virginia Oil & Gas, L.P. and Republic Midstream Marketing, LLC.
(10.3)*	Penn Virginia Corporation 2017 Special Severance Plan Amended and Restated Effective July 18, 2018.
(10.4)	Borrowing Base Increase Agreement and Amendment No. 5 to Credit Agreement dated as of October 26, 2018 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the subsidiaries of the borrower party thereto, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Registrant's Current Report on Form 8-K filed on October 26, 2018).
(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.

\# Filed herewith. Confidential treatment has been requested for this exhibit and confidential portions have been filed separately with the Securities and Exchange Commission.

† 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

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

SECOND AMENDMENT TO SECOND AMENDED AND RESTATED CONSTRUCTION AND FIELD GATHERING AGREEMENT

This Second Amendment to Second Amended and Restated Construction and Field Gathering Agreement (this "***Amendment***") is dated as of July 2, 2018 (the " ***Execution Date***") by and between Republic Midstream, LLC, a Delaware limited liability company ("***Gatherer***"), and Penn Virginia Oil & Gas, L.P., a Texas limited partnership ("***Shipper***"). Gatherer and Shipper may hereinafter be referred to singularly as a "***Party***" and, together, as the " ***Parties***."

WHEREAS, the Parties entered into that certain Second Amended and Restated Construction and Field Gathering Agreement effective as of August 1, 2016 (as amended, the "***Agreement***");

WHEREAS, the Parties entered into that First Amendment to Second Amended and Restated Construction and Field Gathering Agreement, dated as of April 13, 2017; and

WHEREAS, the Parties desire to amend certain provisions of the Agreement;

NOW, THEREFORE, in consideration of the mutual covenants, terms and conditions herein contained, together with other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound hereby, the Parties, for themselves and for their successors and assigns, do hereby mutually covenant and agree as follows:

A. **Amendment of Agreement.** The Agreement is hereby amended as follows:

(1) The definition of "***Additional Segment***" in Article I of the Agreement is hereby amended by replacing the phrase "Dedication Area" with "Dedication Area or Future Units".

(2) The definition of "***Dedication Area***" in Article I of the Agreement is hereby amended and restated to read in its entirety as follows:

> "***Dedication Area***" means**,** collectively, all of the Interests within (a) the areas of Gonzales, Lavaca and Fayette Counties, Texas identified on the map attached hereto as Exhibit A-1, (b) the Other Wells and (c) any Future Wells connected to the Gathering System pursuant to Section 3.3(g).

(3) The definition of "***Receipt Points***" in Article I of the Agreement is hereby amended by replacing the phrase "Dedication Area" with "Dedication Area or with respect to any Future Well for which a Construction Notice has been or is being given pursuant to Section 3.3(a) (unless Gatherer has elected not to connect under Section 3.3(b)), such Future Well as set forth in the applicable Construction Notice".

(4) The definition of "***Shipper's Oil***" in Article I of the Agreement is hereby amended and restated to read in its entirety as follows:

> "***Shipper's Oil***" means all Interests or, with respect to any Future Well for which a Construction Notice has been or is being given pursuant to Section 3.3(a) (unless Gatherer has elected not to connect under Section 3.3(b)), Future Interests from such Future Well, of Shipper in Crude Oil, including, without limitation, all Crude Oil that Shipper owns, controls, acquires or has the right to market within the Dedication Area or such Future Well, as applicable.

(5) Article I of the Agreement is hereby amended by adding the following definitions in appropriate alphabetical order:

> "***Carol Unit***" means that certain 596.91 acre unit described in that certain Designation of Unit recorded in Volume 588, Page 473, Official Records of Lavaca County, Texas, and Volume 1098, Page 818, Official Records of Gonzales County, Texas, as amended by that certain First Amendment to Designation of Unit recorded in Volume 780, Page 345, Official Records of Lavaca County, Texas, and Volume 1275, Page 456, Official Records of Gonzales County, Texas.
>
> "***Carol-Robin Initial Wells***" means the Carol-Robin (SA) Unit 1 Well 1H well and the Carol-Robin (SA) Unit 2 Well 2H well.
>
> "***Future Interests***" means all interests that Shipper (or any of its Affiliates or any successor in interest resulting from any merger, reorganization, consolidation or as part of a sale or other disposition of all or any portion of such interests) now or hereinafter owns, controls, acquires or has the right to market (as such marketing rights may change from time to time) in Crude Oil reserves of, and production from, all leases and mineral fee interests, lands and formations (in each case) in, under or attributable to the Future Units, together with any pool, communitized area or unit, and all interests in any wells, whether now existing or drilled hereafter, on or completed within the Future Units, or within any such pool, communitized area or unit, even though such interests may be incorrectly or incompletely stated, all as the same shall be enlarged by the discharge of any burdens or by the removal of any charges or encumbrances to which any of same maybe subject as of July 2, 2018, and any and all replacements, renewals and extensions or amendments of any of the same; *provided*, *however*, that "Future Interests" shall not include (a) any Interests or (b) any interest of Shipper or any of its Affiliates that must be offered to a third-party working interest partner pursuant to any applicable agreement with such partner in effect on July 2, 2018, and which such partner receives or elects to receive, as applicable under the affected agreement.

"***Future Units***" means the Carol Unit, Robin Unit, Marcia Unit and Shelly Unit, collectively.

"***Future Well Fee***" has the meaning given such term in Section 9.2(e).

"***Future Wells***" means any new wells drilled within the surface outline of the Future Units. For the avoidance of doubt, the term "Future Wells" does not include the Other Wells.

"***Marcia Unit***" means that certain 598.32 acre unit described in that certain Designation of Unit recorded in Volume 654, Page 850, Official Records of Lavaca County, Texas, as amended by First Amendment to Designation of Unit recorded in Volume 781, Page 298, Official Records of Lavaca County, Texas.

"***Marcia-Shelly Initial Wells***" means the Marcia - Shelly (SA) Unit 1 Well1H well and the Marcia-Shelly (SA) Unit 2 Well 2H well.

"***Other Wells***" means the Carol-Robin Initial Wells and the Marcia-Shelly Initial Wells.

"***Other Wells Fee***" has the meaning given such term in Section 9.2(d).

"***Robin Unit***" means that certain 638.146 acre described in that certain Designation of Unit recorded in Volume 673, Page 493, Official Records of Lavaca County, Texas, as amended by that certain First Amendment and Correction to Designation of Unit recorded in Volume 766, Page 199, Official Records, Lavaca County, Texas.

"***Shelly Unit***" means that certain 544.40 acre unit described in that certain Designation of Unit recorded in Volume 663, Page 777, Official Records of Lavaca County, Texas, as amended by that certain First Amendment to Designation of Unit recorded in Volume 686, Page 629, Official Records, Lavaca County, Texas, and by Second Amendment to Designation of Unit recorded in Volume 781, Page 302, Official Records of Lavaca County, Texas.

(6) Section 2.4 of the Agreement is hereby amended by adding the following language at the end of the section:

"Notwithstanding the foregoing, in no event shall Gatherer have the right to provide trucking services with respect to Shipper's Oil from the Future Units (including the Other Wells and any Future Wells) except as may be provided pursuant to Section 3.6 or as otherwise agreed by Shipper."

(7) Section 2.5 of the Agreement is hereby amended by replacing the phrase “Shipper’s Oil” with “Shipper’s Oil (other than with respect to Shipper’s Oil from Future Interests arising from Future Wells which have not been connected to the Gathering System)”.

(8) The introductory section of Section 3.3 of the Agreement is hereby amended and restated to read in its entirety as follows:

> “Gatherer shall expand or extend, add or remove components and operate the Gathering System as necessary to connect Shipper’s wells within the Dedication Area or Future Units as follows:”

(9) Section 3.3(a) of the Agreement is hereby amended and restated to read in its entirety as follows:

> (a) Except with respect to Additional Segments for the Other Wells, Shipper shall notify Gatherer of the need to construct and install an Additional Segment to connect an additional Receipt Point (a “***New Receipt Point***”) within the Dedication Area or the Future Units not included as part of the Base Gathering System (including, for the avoidance of doubt, any Additional Segments for Future Wells) (a “***Construction Notice***”) at least 120 Days prior to the date on which the first well on the first well pad to be connected to such New Receipt Point is expected to be spud. Each Construction Notice delivered by Shipper shall describe in reasonable detail (i) the expected date of first production of Shipper's Oil from the first well pad to be connected to the New Receipt Point (the “***Expected Production Date***”), (ii) the desired location for such New Receipt Point, (iii) Shipper's good faith projection of the daily volumes of Shipper's Oil to be gathered during the initial two (2) years of production from the first well pad to be connected to the New Receipt Point (“***Projected Volumes***”) and (iv) the anticipated API Gravity of Shipper's Oil to be produced from the first well pad to be connected to such New Receipt Point.

(10) Section 3.3(b) of the Agreement is hereby amended and restated to read in its entirety as follows:

> (b) Within 30 Days following the receipt of a Construction Notice, Gatherer shall notify Shipper whether it elects to connect the New Receipt Point to the Gathering System (it being understood that Gatherer must connect (and shall have no election with respect to) any New Receipt Point within a Core Unit); *provided*, *however*, that Gatherer shall not be required to connect any New Receipt Point pursuant to this Section 3.3 in a production unit which already has a Receipt Point connected to the Gathering System (subject to the following proviso) if the aggregate Receipt Points (excluding Receipt Points in the Future Units) connected to the Gathering System following the installation of such New Receipt Point (an “***Excess Receipt***

Point") would be more than one hundred and fifty percent (150%) of the total number of production units (excluding the Future Units) then connected to the Gathering System; *provided*, *further*, that Gatherer shall construct, install, own and operate any Excess Receipt Point if such Excess Receipt Point does not require an additional LACT/ACT Unit and if Shipper reimburses Gatherer for the lesser of (x) $100,000 and (y) 50% of the actual costs associated with construction and installation of such Excess Receipt Point. If Gatherer elects to connect any New Receipt Point (including any Excess Receipt Point), it shall prepare and deliver to Shipper a detailed plan for the connection and/or installation (as applicable) of the New Receipt Point requested by such Construction Notice and the completion of the related Additional Segment (each, a "***Construction Plan***") and shall review with Shipper the design for constructing and/or modifying and operating such Additional Segment prior to finalizing the Construction Plan. Any Additional Segment and New Receipt Point (if applicable) that Gatherer is required to build (with respect to Receipt Points within the Core Units) or has elected to build (with respect to Receipt Points outside the Core Units, including the Future Units) in accordance with this Section 3.3(b), Section 3.3(f) or Section 3.3(g) shall be considered a "***Required Connection***."

(11) Section 3.3(c) of the Agreement is hereby amended and restated to read in its entirety as follows:

(c) Gatherer shall use commercially reasonable efforts to complete the construction of any Required Connection so that it is operational by not later than 30 Days prior to the Expected Production Date, subject to Force Majeure. Any Other Wells, Future Wells, and production units (other than Future Units) connected to the Gathering System by Gatherer pursuant to this Section 3.3 shall become "***Additional Units***."

(12) Section 3.3(d) of the Agreement is hereby amended by replacing the phrase "New Receipt Point" in the first sentence with "New Receipt Point (other than with respect to Receipt Points in the Future Units that have not been connected to the Gathering System)".

(13) Section 3.3(f) is added to the Agreement as follows:

(f) Notwithstanding anything herein to the contrary, Gatherer shall, at its sole risk, cost and expense, install pipeline facilities and connect the Other Wells to a point on the Gathering System pursuant to a construction plan mutually agreed to by Shipper and Gatherer. Shipper shall pay the Other Wells Fee on Shipper's Oil gathered from the Other Wells in accordance with Section 9.2(d).

(14) Section 3.3(g) is added to the Agreement as follows:

> (g) For each Future Well Shipper drills in the Future Units, if any, Shipper shall deliver to Gatherer a Construction Notice as set forth in Section 3.3(a) and Gatherer shall have the right with respect to any such Future Well, at its sole risk, cost and expense, to install an Additional Segment to connect a Receipt Point for such Future Well to the Gathering System, such election to be made in accordance with Section 3.3(b). Any Future Well connected by Shipper pursuant to this Section 3.3(g) shall become part of the Dedication Area for purposes of this Agreement. Shipper shall pay the Future Well Fee on Shipper's Oil gathered from Future Wells within the Future Units in accordance with Section 9.2(e). For the avoidance of doubt, Shipper shall not have any obligation with respect to the production from any Future Well to the extent Gatherer has not elected to connect such Future Well under Section 3.3(b) of this Agreement.

(15) Section 3.8 of the Agreement is hereby amended and restated to read in its entirety as follows:

> 3.8 Gatherer and Shipper shall collaborate to ensure that the Gathering System is configured in such a manner as to have reasonable ingress and egress to access roads and wells within the Dedication Area and for any Future Well that Gatherer has elected to connect or for which a Construction Notice has been given in accordance with Section 3.3(g). With respect to any access roads constructed or to be constructed within the Dedication Area or the Future Units (solely with respect to any Future Well that Gatherer has elected to connect or for which a Construction Notice has been given in accordance with Section 3.3(g)), such Party shall grant the other Party access to and use thereof. Each Party shall be responsible, and shall reimburse the other Party, for any damage caused by such Party to the other Party's roads within the Dedication Area or the Future Units, ordinary wear and tear excepted.

(16) Section 4.5 of the Agreement is hereby amended and restated to read in its entirety as follows:

> 4.5 Shipper shall reimburse Gatherer for the actual costs of the ongoing power requirements for operation of Gatherer's LACT units and injection pump facilities at the Receipt Points. Gatherer shall provide, at its sole risk, cost and expense, power for the CDP. If Shipper desires to connect to an electric power source at a Receipt Point for which Gatherer paid the electricity installation cost and that would otherwise require Shipper to share the cost by the Guadalupe Valley Electric Cooperative or other entity providing the electricity installation, then Shipper shall pay Gatherer the lesser of (a) 20% of Shipper's share of such installation cost (as determined by the Guadalupe Valley Electric Cooperative or other entity providing the electricity

installation) and (b) $5,000, in each case for the right to share such electric power source with Gatherer. Shipper shall be responsible for and pay the costs of any electricity used by Shipper and shall be responsible for the installation and maintenance of its own electric meter.

(17) Section 6.5 of the Agreement is hereby amended by replacing each instance of "Interests" with "Interests and Future Interests".

(18) Section 9.2 of the Agreement is hereby amended and restated to read in its entirety as follows:

9.2 As consideration of the services rendered by Gatherer under this Agreement, from and after the Effective Date, Shipper shall pay to Gatherer the following fees each Month (the "***Fees***"):

(a) During the first thirty-six (36) Months of the Term, a Gathering Fee equal to $0.75 per Barrel on all of Shipper's Oil delivered at the Delivery Points via the Gathering System (other than from the Excluded Units, Outside Units, Other Wells or Future Wells) during such Month (the "***Initial Gathering Fee***");

(b) After the first thirty-six (36) Months of the Term and for the remainder of the Term, a gathering fee equal to $1.30 per Barrel on all of Shipper's Oil delivered at the Delivery Points via the Gathering System (other than from the Excluded Units, Outside Units, Other Wells or Future Wells) during such Month (as adjusted by any PPI Adjustment, the "***Subsequent Gathering Fee***");

(c) A gathering fee on all of Shipper's Oil delivered at the Delivery Points via the Gathering System from wells in the Excluded Units and the Outside Units ("***Excluded Volumes***") equal to $1.00 per Barrel during such Month (as adjusted by any PPI Adjustment, the "***Preferential Fee***"); *provided*, *however*, that in the event Shipper has delivered less than the Minimum Volume Commitment in the applicable Month, the Preferential Fee will be equal to the gathering fee then in effect with respect to such amount of Excluded Volumes as is necessary for Shipper to meet the Minimum Volume Commitment;

(d) A gathering fee on all of Shipper's Oil delivered at the Delivery Points via the Gathering System from the Other Wells (the "***Other Wells Fee***") as follows: (i) until Shipper has delivered 2,000,000 barrels in aggregate from the Other Wells, the Other Wells Fee shall be equal to $1.20 per Barrel; and (ii) after Shipper has delivered 2,000,000 barrels in aggregate from the Other Wells, the Other Wells Fee shall be equal to $1.00 per Barrel;

(e) A gathering fee on all of Shipper's Oil delivered at the Delivery Points via the Gathering System from any Future Well equal to $1.00 per Barrel during such Month (the "***Future Well Fee***");

(f) During the first thirty-six (36) Months of the Term, a trucking fee equal to the actual documented trucking costs incurred by or on behalf of Gatherer for such volumes of Shipper's Oil trucked by or on behalf of Gatherer (which shall in no event include Shipper's Oil from the Other Wells or Future Wells except as otherwise agreed by Shipper) from the Receipt Points to the CDP during such Month (the "***Initial Trucking Fee***");

(g) After the first thirty-six (36) Months of the Term and for the remainder of the Term, a trucking fee equal to $1.30 per Barrel of Shipper's Oil trucked by or on behalf of Gatherer (which shall in no event include Shipper's Oil from the Other Wells or Future Wells except as otherwise agreed by Shipper) from the Receipt Points to the CDP during such Month (as adjusted by any PPI Adjustment, the "***Subsequent Trucking Fee***"); and

(h) A truck loading fee equal to $0.10 per Barrel on all of Shipper's Oil either loaded onto or unloaded from trucks at the CDP (which shall in no event include Shipper's Oil from the Other Wells or Future Wells except as otherwise agreed by Shipper) or any other Delivery Point agreed to by the Parties during such Month (the "***Truck Loading Fee***").

For clarification purposes, Shipper shall not be required to pay the Initial Gathering Fee, the Subsequent Gathering Fee or the Preferential Fee on any of Shipper's Oil trucked to the CDP (whether by or on behalf of Gatherer or otherwise).

(19) Section 9.4 of the Agreement is hereby amended by adding the following language at the end of the section:

Notwithstanding the foregoing, for any month in which Shipper delivers an average of 20,000 or more Barrels of Oil per Day, the Upside Adjustment to the Truck Loading Fee shall be waived for all Oil delivered to the Gathering System from Shipper's wells outside the Dedication Area.

(20) Section 9.5 of the Agreement is hereby amended and restated to read in its entirety as follows:

9.5 From and after the Effective Date, to the extent available, Shipper shall deliver to Gatherer at the Receipt Point(s) the first 20,000 Barrels of Oil per Day (i) produced from Shipper or its Affiliate's operated wells in Lavaca, Fayette, and Gonzales Counties, Texas, which shall include volumes attributable to non-operating working interest owners insofar and only insofar as Shipper or its Affiliates has the right to market such volumes and the non-operators have not elected to take their share of production in kind; and (ii) produced from wells in Lavaca, Fayette, and Gonzales Counties, Texas in which Shipper, on or after the Effective Date, resigns as operator (other than any resignation pursuant to a legitimate business purpose (other than circumvention of Shipper's obligations under this Section 9.5)) and has the right to take its share of production in kind. Notwithstanding the foregoing, Shipper shall be deemed to have satisfied this obligation if the Monthly average of the daily volumes delivered in a given Month equals or exceeds 20,000 Barrels per day.

(21) Section 19.2(e) of the Agreement is hereby amended by replacing the phrase "Dedication Area" with "Dedication Area or Future Units".

B. **Ratification; Primacy**. Except as expressly amended by this Amendment, all of the terms, provisions, covenants and conditions contained in the Agreement remain in full force and effect; *provided*, if there is ever any conflict between the Agreement and this Amendment, the terms, provisions, covenants and conditions contained in this Amendment shall govern. The terms and provisions of the Agreement as amended by this Amendment are binding upon and inure to the benefit of the Parties, their representatives, successors and assigns. As amended by this Amendment, the Agreement is ratified and confirmed by the Parties, and declared to be a valid and enforceable contract between them.

C. **Counterparts**. This Amendment may be executed in as many counterparts as deemed necessary. When so executed, the aggregate counterparts shall constitute one agreement and shall have the same effect as if all Parties signing counterparts had executed the same instrument.

D. **Amendment; Waiver**. Neither this Amendment nor the Agreement may be amended or modified except pursuant to a written instrument signed by all of the Parties. Each Party may waive on its own behalf compliance by any other Party with any term or provision hereof; *provided*, *however*, that any such waiver shall be in writing and shall not bind the non-waiving Party. The waiver by any Party of a breach of any term or provision shall not be construed as a waiver of any subsequent breach of the same or any other provision.

E. **Joint Preparation**. The Parties agree and confirm that this Amendment was prepared jointly by all Parties and not by any one Party to the exclusion of the other.

F. **No Third Party Beneficiaries**. This Amendment is not intended to confer upon any person not a party hereto any rights or remedies hereunder, and no person other than the Parties is entitled to rely on or enforce any provision hereof.

G. **Miscellaneous Provisions**. The provisions of Articles XVII, XIX, XX and XXI of the Agreement are incorporated herein by this reference as if set out fully herein and shall apply in all respects to this Amendment.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the Parties have executed this Amendment as of the day and year hereinabove first written.

REPUBLIC MIDSTREAM, LLC

By:

Name:
Title:

PENN VIRGINIA OIL & GAS, L.P.

By: Penn Virginia Oil & Gas GP LLC,
its general partner

By:

Name:
Title:

* Confidential treatment has been requested with respect to portions of this agreement as indicated by "[***]" and such confidential portions have been deleted and filed separately with the Securities and Exchange Commission pursuant to Rule 24b-2 of the Exchange Act of 1934, as amended.

FIRST AMENDMENT TO FIRST AMENDED AND RESTATED CRUDE OIL MARKETING AGREEMENT

This First Amendment to First Amended and Restated Crude Oil Marketing Agreement (this " Amendment") is dated as of July 2, 2018 (the "Execution Date"), by and between Penn Virginia Oil & Gas, L.P. (" PVOG") and Republic Midstream Marketing, LLC ("Republic"). PVOG and Republic may be referred to individually as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, PVOG and Republic are parties to that certain First Amended and Restated Crude Oil Marketing Agreement, dated as of August 1, 2016 (as amended, the "Marketing Agreement"), pursuant to which PVOG agreed to deliver certain volumes of crude oil to Republic, and Republic agreed to accept said volumes, pursuant to the terms thereof; and

WHEREAS, the Parties wish to amend the Marketing Agreement to clarify certain provisions.

NOW THEREFORE, in consideration of the mutual covenants and agreements of the Parties herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged by the Parties, the Parties hereby agree as follows:

1. Amendment to Marketing Agreement. Effective as of May 1, 2018 (the "Effective Date"), Section 3.b of Article II of the Marketing Agreement shall be amended to read in its entirety as follows:

> ""Transportation Deduction" means the sum of (i) the Committed Shipper B Base Rate Transportation Rate (the "Shipper B Base Rate") as defined from time to time in the KMCC Rate Tariff as supplemented, revised or otherwise updated (the "KMCC Rate Tariff"), less [***], (ii) the pipeline loss allowance charged by KMCC, which rate is currently a deduction of 0.250% of the crude oil received with an API Gravity at or below 45.0 degrees and 0.375% of the crude oil received with an API Gravity above 45.0 degrees at the PVOG Delivery Point to cover for losses associated with the transportation of crude oil on KMCC, (iii) any other fees reflected in the KMCC Regulations Tariff that are charged for PVOG's crude oil movements ("Other Fees") and which are applicable to similarly situated shippers under the KMCC Regulations Tariff; provided however, that "Other Fees" shall not include any amounts, charges or fees related to a rate schedule in the KMCC Rate Tariff other than the Shipper B Base Rate, and (iv) a marketing fee of [***] per barrel purchased and sold hereunder. For the avoidance of doubt, after the initial thirty-six (36) months of the term, there shall be no deduction to the KMCC Rate Tariff under clause (i) above in this Section 3.b."

2. Miscellaneous.

(a) Ratification; Primacy. Except as expressly amended by this Amendment, all of the terms, provisions, covenants and conditions contained in the Marketing Agreement remain in full force and effect; provided, if there is ever any conflict between the Marketing Agreement and this Amendment, the terms, provisions, covenants and conditions contained in this Amendment shall govern. The terms and provisions of the Marketing Agreement as amended by this Amendment are binding upon and inure to the benefit of the Parties, their representatives, successors and assigns. As amended by this Amendment, the Marketing Agreement is ratified and confirmed by the Parties, and declared to be a valid and enforceable contract between them

(b) Interpretation. The Parties acknowledge that (i) the Parties have had the opportunity to exercise business discretion in relation to the negotiation of the details of the transaction contemplated hereby, (ii) this Amendment is the result of arms-length negotiations from equal bargaining positions and (iii) the Parties and their respective counsel participated in the preparation and negotiation of this Amendment. Any rule of construction that a contract be construed against the drafter shall not apply to the interpretation or construction of this Amendment.

(c) Authority. Each Party represents that the individual executing this Amendment on behalf of such Party has the authority to execute this Amendment and bind such Party to the terms hereof.

(d) Parties in Interest. The terms and provisions of this Amendment shall be binding upon and inure to the benefit of Seller and Buyer and their respective successors and permitted assigns. Notwithstanding anything contained in this Amendment to the contrary, nothing in this Amendment, expressed or implied, is intended to confer on any Person, other than the Parties or their respective successors and permitted assigns, any rights, remedies, obligations or Liabilities under or by reason of this Amendment.

(e) Governing Law. This Amendment and the legal relations between the Parties shall be governed by and construed in accordance with the laws of the state of Texas without regard to principles of conflicts of law which would require the application of the laws of another jurisdiction.

(f) Venue. THE PARTIES HEREBY IRREVOCABLY SUBMIT TO THE EXCLUSIVE JURISDICTION OF THE STATE AND FEDERAL COURTS OF THE UNITED STATES OF AMERICA LOCATED IN HARRIS COUNTY, TEXAS AND APPROPRIATE APPELLATE COURTS THEREFROM, AND EACH PARTY HEREBY IRREVOCABLY AGREES THAT ALL CLAIMS IN RESPECT OF SUCH DISPUTE, CONTROVERSY OR CLAIM MAY BE HEARD AND DETERMINED IN SUCH COURTS. THE PARTIES HEREBY IRREVOCABLY WAIVE, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAWS, ANY OBJECTION WHICH THEY MAY NOW OR HEREAFTER HAVE TO THE LAYING OF VENUE OF ANY SUCH DISPUTE, CONTROVERSY OR CLAIM BROUGHT IN ANY SUCH COURT OR ANY DEFENSE OF INCONVENIENT FORUM FOR THE MAINTENANCE OF SUCH DISPUTE, CONTROVERSY OR CLAIM. EACH PARTY AGREES THAT A JUDGMENT

* Confidential treatment has been requested with respect to portions of this agreement as indicated by "[***]" and such confidential portions have been deleted and filed separately with the Securities and Exchange Commission pursuant to Rule 24b-2 of the Exchange Act of 1934, as amended.

IN ANY SUCH DISPUTE MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY APPLICABLE LAW.

(g) Severability. If any term or other provision of this Amendment is invalid, illegal or incapable of being enforced by any rule of law or public policy, all other conditions and provisions of this Amendment shall nevertheless remain in full force and effect so long as the economic or legal substance of the transactions contemplated hereby is not affected in any adverse manner to any Party. Upon such determination that any term or other provision is invalid, illegal or incapable of being enforced, the Parties shall negotiate in good faith to modify this Amendment so as to effect the original intent of the Parties as closely as possible in an acceptable manner to the end that the transactions contemplated hereby are fulfilled to the extent possible.

(h) Counterparts. This Amendment may be executed in counterparts, each of which shall be deemed an original instrument, but all such counterparts together shall constitute but one agreement. A Party's delivery of an executed counterpart signature page by facsimile (or email) is as effective as executing and delivering this Amendment in the presence of the other Party. No Party shall be bound until such time as the other Party has executed a counterpart of this Amendment.

(i) Incorporation. Capitalized terms used but not defined herein have the meaning set forth in the Marketing Agreement. The terms of Section 8 (Assignment), Section 9 (Notice), Section 10 (Limitation of Damages) and Section 13 (Entire Agreement) of Article IV of the Marketing Agreement are incorporated herein, *mutatis mutandis*.

[Signature page follows.]

* Confidential treatment has been requested with respect to portions of this agreement as indicated by "[***]" and such confidential portions have been deleted and filed separately with the Securities and Exchange Commission pursuant to Rule 24b-2 of the Exchange Act of 1934, as amended.

IN WITNESS WHEREOF, this Amendment has been executed by the Parties as of the Execution Date, but effective for Section 1 as of the Effective Date.

PENN VIRGINIA OIL & GAS, L.P.

By: Penn Virginia Oil & Gas GP, LLC
its general partner

By: /s/ Jill T. Zively______________

Name: Jill T. Zively

Title: Vice President, Land and Marketing

REPUBLIC MIDSTREAM MARKETING, LLC

By: /s/ Daniel R. Revers___________

Name: Daniel R. Revers

Title: President

* Confidential treatment has been requested with respect to portions of this agreement as indicated by "[***]" and such confidential portions have been deleted and filed separately with the Securities and Exchange Commission pursuant to Rule 24b-2 of the Exchange Act of 1934, as amended.

PENN VIRGINIA CORPORATION

2017 SPECIAL SEVERANCE PLAN

Amended and Restated Effective July 18, 2018

Exhibit 10.3

PENN VIRGINIA CORPORATION
2017 SPECIAL SEVERANCE PLAN
Amended and Restated Effective July 18, 2018

Section 1. Effective Date.

Effective as of July 18, 2018, the Company, as defined below, has amended and restated the Plan, as described herein. The Plan is established by the Company for the benefit of Participants. Any payments to be made under the Plan shall be subject to, and contingent upon the occurrence of, in all respects, the Closing.

Section 2. Term.

Subject to Section 1 hereof, the Plan shall remain in effect until modified or terminated pursuant to Section 10 hereof.

Section 3. Definitions.

(a) "**Base Pay**" means the base salary or base wages that a Participant earns during a week (assuming in the case of hourly employees, a 40-hour work week), based upon rate of pay in effect for the Participant immediately before the Participant's termination of employment, excluding overtime, bonuses, incentive compensation or any other special payments; and is used to compute the amount of the Severance Benefit.

(b) **"Board"** means the Board of Directors of the Company.

(c) **"Cause"** has the meaning ascribed to such term in any employment agreement between the Participant and the Company or, if none, means a Participant's: (i) willful and continued failure to substantially perform the Participant's duties with the Company or any affiliate (other than any such failure resulting from the Participant's Disability), (ii) conviction of a felony, (iii) willful engagement in gross misconduct materially and demonstrably injurious to the Company or any affiliate or (iv) commission of one or more significant acts of dishonesty as regards the Company or any affiliate.

(d) **"Closing"** means the date on which a Qualified Liquidity Event is consummated.

(e) **"Code"** means the Internal Revenue Code of 1986, as amended, and any guidance and/or regulations promulgated thereunder.

(f) **"Committee"** means the Compensation & Benefits Committee of the Board or another duly constituted committee of members of the Board.

(g) **"Company"** means Penn Virginia Corporation and its affiliated companies and subsidiaries, and following the Closing, shall include any successor.

(h) "**Disability**" means a Participant is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or which has lasted or can be expected to last for a continuous period of not less than 12 months.

(i) "**Employee**" means an individual who is an employee on the payroll of the Company and is normally scheduled to work 30 or more hours per week for the Company. The term "Employee" shall not include any person providing services to the Company through a temporary service or on a leased basis or who is hired by the Company as an independent contractor, consultant, or otherwise as a person who is not an employee for purposes of withholding United States federal income or employment taxes, as evidenced by payroll records or a written agreement with the individual, regardless of any contrary governmental agency determination or judicial holding relating to such status or tax withholding.

(j) "**ERISA**" means the Employee Retirement Income Security Act of 1974, as amended.

(k) "**Good Reason**" has the meaning ascribed to such term in any employment agreement between the Participant and the Company or, if none, means the occurrence of any of the following events or conditions: (i) a material reduction in the Participant's base salary or annual cash incentive compensation opportunity from that in effect immediately prior to the Closing or (ii) the relocation of the Participant to a location more than fifty (50) miles from the location at which the Participant is based immediately prior to the Closing.

(l) **"Participant"** means an Employee who participates in the Plan pursuant to Section 4 of the Plan.

(m) **"Person"** means an individual, partnership, corporation, unincorporated organization, joint stock company, limited liability company, trust, joint venture or other legal entity, or a governmental agency or political subdivision thereof.

(n) **"Plan"** means this Penn Virginia Corporation 2017 Special Severance Plan, Amended and Restated Effective July 18, 2018, and as further amended from time to time.

(o) **"Protection Period"** means the period commencing on the Closing and ending on the date that is six months following the Closing.

(p) "**Qualified Liquidity Event**" means the consummation of a transaction or series of related transactions in which either:

(1) one Person (or more than one Person acting as a group) acquires beneficial ownership of stock of the Company that, together with the stock held by such Person or group, constitutes more than 30% of the total fair market value or total voting power of the stock of the Company;

(2) a majority of the members of the Board are replaced during any twelve-month period by directors whose appointment or election is not endorsed by a majority of the Board before the date of appointment or election; or

(3) one Person (or more than one Person acting as a group), acquires (or has acquired during the twelve-month period ending on the date of the most recent acquisition) assets from the

Company that have a total gross fair market value equal to or more than 40% of the total gross fair market value of all of the assets of the Company immediately before such acquisition(s).

(q) **"Severance Benefit"** means the payments set forth in Exhibit A (for the Chief Executive Officer and the Company's executive officers) or Exhibit B (for all other Participants), as applicable, to this Plan. In addition, the "**Severance Benefit**" for all Participants shall include (i) an additional amount (payable in a lump sum) equal to the annual bonus, if any, earned by the Participant for the year preceding the year of termination (based on the target level of performance) to the extent unpaid as of the Participant's last day of employment, and (ii) if the Participant elects such continuation coverage, Company-paid COBRA continuation coverage (at the same contribution rate paid by the Company for active employees) for the Participant and his or her covered dependents following the Participant's date of termination for the number of weeks (based on the position of the Participant) indicated above (or such shorter period during which COBRA coverage is provided to the Participant).

Section 4. Eligibility. All Employees shall be eligible to participate in the Plan.

Section 5. Severance Benefit.

(a) Termination of Employment without Cause or Resignation for Good Reason. In the event that a Participant's employment is terminated by the Company without Cause or a Participant resigns with Good Reason during the Protection Period, then subject to the terms and conditions of the Plan, *including*, without limitation, Section 5(c) below, such Participant will receive the Severance Benefit.

(b) Termination of Employment for any Other Reason. In the event that a Participant's employment is terminated by the Company during the Protection Period for any other reason, including, without limitation, (A) Participant's resignation without Good Reason or (B) a termination of Participant's employment by the Company for Cause or due to Participant's Disability or death, then such Participant shall not be entitled to receive any payments under this Plan.

(c) Release of Claims; Payment of Benefits. Payment of the Severance Benefit shall be made on the date that is sixty (60) days following the Participant's last day of employment (or such earlier date as the Company may determine, provided that such earlier date does not violate Code Section 409A to the extent applicable), subject to (i) the Participant's execution (and non-revocation) of a general release of claims in favor of the Company and its parent, subsidiaries and affiliates and each of their respective affiliates, agents, employees, directors, equity holders, representatives and such other parties as the Company reasonably determines, which release shall be in substantially the form attached hereto as Exhibit C, and will be delivered by the Company to the Participant within five (5) days following the Participant's last day of employment, and must be executed by the Participant and returned to the Company within forty-five (45) days following Participant's receipt, and (ii) for the Chief Executive Officer and any other executive officers of the Company, the Participant's execution of a separation agreement, in a form provided by the Company, that includes post-employment customary confidentiality, non-disparagement, non-solicitation, non-competition and other customary covenants in favor of the Company, which covenants shall be perpetual with respect to confidentiality and non-disparagement, and shall otherwise run for the same period used to determine the amount of the Severance Benefit for the Participant.

Section 6. Administration.

(a) In the event of any conflict or inconsistency between another document and the terms of the Plan, the terms and conditions of the Plan shall govern and control.

(b) The Plan shall be administered by the Committee in its sole and absolute discretion, and all determinations by the Committee shall be final, binding and conclusive on all parties and be given the maximum possible deference allowed by law. The Committee is the “named fiduciary” of the Plan for purposes of ERISA and will be subject to the fiduciary standards of ERISA when acting in such capacity.

(c) The Committee shall have the authority, consistent with the terms of the Plan, to (i) designate Participants, (ii) determine the terms and conditions relating to the Severance Benefit, if any, (iii) interpret, administer, reconcile any inconsistency, correct any defect and/or supply any omission in the Plan, (iv) establish, amend, suspend or waive any rules and procedures with respect to the Plan, and (v) make any other determination and take any other action that the Committee deems necessary or desirable for administration of the Plan, including, without limitation, the timing and amount of payments. The Committee may delegate to one or more of the officers of the Company the authority to act on behalf of the Committee.

Section 7. **Funding.**

The obligations of the Company under the Plan are not funded through contributions to a trust or otherwise, and all benefits shall be payable from the general assets of the Company. Nothing contained in the Plan shall give a Participant any right, title or interest in any property of the Company. Participants shall be mere unsecured creditors of the Company.

Section 8. ERISA.

The Plan is not intended to provide retirement income or to defer the receipt of payments hereunder to the termination of a Participant's employment or beyond. The Plan is not a pension that is subject to ERISA. This Plan is an “employee welfare benefit plan,” as defined in Section 3(1) of ERISA. This document constitutes both the written instrument under which the Plan is maintained and the required summary plan description for the Plan.

Section 9. Code Section 409A.

(a) Compliance. Notwithstanding anything herein to the contrary, this Plan is intended to be interpreted and applied so that the payments and benefits set forth herein either shall be exempt from the requirements of Code Section 409A, or shall comply with the requirements of Code Section 409A, and, accordingly, to the maximum extent permitted, this Plan shall be interpreted to be exempt from or in compliance with Code Section 409A. To the extent that the Company determines that any provision of this Plan would cause a Participant to incur any additional tax or interest under Code Section 409A, the Company shall be entitled to reform such provision to attempt to comply with or be exempt from Code Section 409A through good faith modifications. To the extent that any provision hereof is modified in order to comply with Code Section 409A, such modification shall be made in good faith and shall, to the maximum extent reasonably possible, maintain the original intent and economic benefit to Participants and the Company without violating the provisions of Code Section 409A. Notwithstanding any of the foregoing to the contrary, none of the Company or its subsidiaries or affiliates or any of their officers, directors, members, employees, agents, advisors, predecessors, successors, or equity holders shall have any liability for the failure of this Plan to be exempt from, or to comply with, the requirements of Section 409A of the Code. Each payment and/or benefit provided hereunder shall be a payment in a series of separate payments for purposes of Code Section 409A.

(b) Separation from Service. Notwithstanding anything in this Plan to the contrary, a termination of employment shall not be deemed to have occurred for purposes of any provision of this Plan unless such termination is also a "separation from service" within the meaning of Code Section 409A.

(c) Specified Employee. Notwithstanding anything in this Plan to the contrary, if a Participant is deemed to be a "specified employee" within the meaning of Code Section 409A, any payments or benefits due upon a termination of Participant's employment under any arrangement that constitutes a "deferral of compensation" within the meaning of Code Section 409A (whether under this Plan or any other plan, program or payroll practice) and which do not otherwise qualify under the exemptions under Treasury Regulations Section 1.409A- 1 (including without limitation, the short-term deferral exemption and the permitted payments under Treasury Regulations Section 1.409A-1 (b)(9)(iii)(A)), shall be delayed and paid or provided to Participant in a lump sum on the earlier of (i) the date which is six (6) months and one (1) day after Participant's "separation from service" (as such term is defined in Code Section 409A) for any reason other than death, and (ii) the date of Participant's death.

Section 10. Amendment or Termination.

Prior to the Closing, the Committee may amend or terminate the Plan at any time, without notice, and for any or no reason, except as prohibited by law. Any action of the Company in amending or terminating the Plan will be taken in a non-fiduciary capacity. Upon or after the Closing, the Company and the Committee may not, without a Participant’s written consent, amend or terminate the Plan in any way, nor take any other action, that (i) prevents that Participant from becoming eligible for the Severance Benefits under the Plan, or (ii) reduces or alters to the detriment of the Participant the Severance Benefits payable, or potentially payable, to a Participant under the Plan (including, without limitation, imposing additional conditions). The Plan shall automatically terminate upon the later of the (i) payment of all applicable benefits under the Plan or (ii) 90 days following the end of the Protection Period.

Section 11. Employment at Will.

Nothing in this Plan or any other act of the Company shall be considered effective to change a Participant's status as an at-will employee or guarantee any duration of employment. Either the Company or a Participant may terminate the employment relationship at any time, for any reason or no reason, and with or without advance notice.

Section 12. Transfer and Assignment.

In no event may any Participant sell, transfer, anticipate, assign or otherwise dispose of any right or interest under the Plan. At no time will any such right or interest be subject to the claims of creditors nor liable to attachment, execution or other legal process.

Section 13. Severability.

If any provision of the Plan is held invalid or unenforceable, its invalidity or unenforceability will not affect any other provision of the Plan, and the Plan will be construed and enforced as if such provision had not been included.

Section 14. Successors.

Any successor to the Company of all or substantially all of the Company's business and/or assets (whether direct or indirect and whether by purchase, merger, consolidation, liquidation or other transaction) will assume the obligations under the Plan and agree expressly to perform the obligations under the Plan in the same manner and to the same extent as the Company would be required to perform such obligations in the absence of a succession. For all purposes under the Plan, the term "Company" will include any successor to the Company's business and/or assets which become bound by the terms of the Plan by operation of law, or otherwise.

Section 15. Withholding; Taxes.

The Company shall withhold from any Severance Benefit all federal, state and local income or other taxes required to be withheld therefrom and any other required payroll deductions.

Section 16. Compensation.

Benefits payable hereunder shall not constitute compensation under any other plan or arrangement, except as expressly provided in such plan or arrangement.

Section 17. Gender; Number; Headings.

Except when otherwise indicated by the context, any masculine terminology shall also include the feminine, and the definition of any term in the singular shall also include the plural. The headings and captions herein are provided for reference and convenience only, shall not be considered part of the Plan, and shall not be employed in the construction of the Plan.

Section 18. Entire Agreement.

This Plan represents the entire agreement of the Company and the Participants with respect to the subject matter hereof and supersedes all prior understandings, whether written or oral.

Section 19. Governing Law.

The provisions of the Plan will be construed, administered and enforced in accordance with ERISA and, to the extent applicable, the laws of the State of Texas without regard to its choice of law provisions.

Section 20. Claims and Appeals.

(a) Claims Procedure. Any employee or other person who believes he or she is entitled to any payment under the Plan may submit a claim in writing to the Committee within 90 days of the earlier of (i) the date the claimant learned the amount of his or her benefits under the Plan or (ii) the date the claimant learned that he or she will not be entitled to any benefits under the Plan. If the claim is denied (in full or in part), the claimant will be provided a written notice explaining the specific reasons for the denial and referring to the provisions of the Plan on which the denial is based. The notice also will describe any additional information needed to support the claim and the Plan's procedures for appealing the denial. The denial notice will be provided within 90 days after the claim is received. If special circumstances require an extension of time (up to 90 days), written notice of the extension will be given within the initial 90 day period. This notice of extension will indicate the special circumstances requiring the extension of time and the date by which the Committee expects to render its decision on the claim.

(b) Appeal Procedure. If the claimant's claim is denied, the claimant (or his or her authorized representative) may apply in writing to the Committee for a review of the decision denying the claim. Review must be requested within 60 days following the date the claimant received the written notice of their claim denial or else the claimant loses the right to review. The claimant (or representative) then has the right to review and obtain copies of all documents and other information relevant to the claim, upon request and at no charge, and to submit issues and comments in writing. The Committee will provide written notice of its decision on review within 60 days after it receives a review request. If additional time (up to 60 days) is needed to review the request, the claimant (or representative) will be given written notice of the reason for the delay. This notice of extension will indicate the special circumstances requiring the extension of time and the date by which the Committee expects to render its decision. If the claim is denied (in full or in part), the claimant will be provided a written notice explaining the specific reasons for the denial and referring to the provisions of the Plan on which the denial is based. The notice also will include a statement that the claimant will be provided, upon request and free of charge, reasonable access to, and copies of, all documents and other information relevant to the claim and a statement regarding the claimant's right to bring an action under Section 502(a) of ERISA.

Section 21. Certain Excise Taxes.

Notwithstanding anything to the contrary in this Plan, if a Participant is a “disqualified individual” (as defined in Section 280G(c) of the Code), and the Severance Benefit provided for under this Plan, together with any other payments and benefits which the Participant has the right to receive from the Company, would constitute a “parachute payment” (as defined in Section 280G(b)(2) of the Code), then the Severance Benefit provided for under this Plan shall be either (a) reduced (but not below zero) so that the present value of such total amounts and benefits received by the Participant from the Company will be one dollar ($1.00) less than three times the Participant’s “base amount” (as defined in Section 280G(b)(3) of the Code) and so that no portion of such amounts and benefits received by the Participant shall be subject to the excise tax imposed by Section 4999 of the Code, or (b) paid in full, whichever produces the better net after-tax position to the Participant (taking into account any applicable excise tax under Section 4999 of the Code and any other applicable taxes). The determination as to whether any such reduction in the amount of the payments provided hereunder is necessary shall be made by the Company in good faith. If a reduced payment is made or provided and through error or otherwise that payment, when aggregated with other payments and benefits from the Company used in determining if a parachute payment exists, exceeds one dollar ($1.00) less than three times the Participant’s base amount, then the Participant shall immediately repay such excess to the Company upon notification that an overpayment has been made. Nothing in this Plan shall require the Company to be responsible for, or have any liability or obligation with respect to, the Participant’s excise tax liabilities under Section 4999 of the Code.

Section 22. Additional Information.

Plan Name:	Penn Virginia Corporation 2017 Special Severance Plan
Plan Sponsor:	Penn Virginia Corporation 14701 Saint Mary’s Lane, Suite 275 Houston, TX 77079
Identification Numbers:	**EIN:** 23-1184320 **PLAN:** 001
Plan Year:	January 1 through December 31
Plan Administrator:	Penn Virginia Corporation Attn: Compensation & Benefits Committee of the Board of Directors 14701 Saint Mary’s Lane, Suite 275 Houston, TX 77079 (713) 722-6500

Agent for Service of Legal Process: Penn Virginia Corporation
Attn: General Counsel
14701 Saint Mary's Lane, Suite 275
Houston, TX 77079

Service of process also may be made upon the Administrator.

Type of Plan: Severance Plan/Employee Welfare Benefit Plan

Plan Costs: The cost of the Plan is paid by the Company.

Section 23. Statement of ERISA Rights .

As a Participant under the Plan, you have certain rights and protections under ERISA:

You may examine (without charge) all Plan documents, including any amendments and copies of all documents filed with the U.S. Department of Labor. These documents are available for your review in the Company's Human Resources Department.

You may obtain copies of all Plan documents and other Plan information upon written request to the Administrator. A reasonable charge may be made for such copies.

In addition to creating rights for Participants, ERISA imposes duties upon the people who are responsible for the operation of the Plan. The people who operate the Plan (called "fiduciaries") have a duty to do so prudently and in the interests of you and the other Participants. No one, including the Company or any other person, may fire you or otherwise discriminate against you in any way to prevent you from obtaining a benefit under the Plan or exercising your rights under ERISA. If your claim for payments or benefits under the Plan is denied, in whole or in part, you must receive a written explanation of the reason for the denial. You have the right to have the denial of your claim reviewed. (The claim review procedure is explained in Section 20 above.)

Under ERISA, there are steps you can take to enforce the above rights. For example, if you request materials and do not receive them within 30 days, you may file suit in a federal court. In such a case, the court may require the Administrator to provide the materials and to pay you up to $110 a day until you receive the materials, unless the materials were not sent due to reasons beyond the control of the Administrator. If you have a claim which is denied or ignored, in whole or in part, you may file suit in a federal court. If it should happen that you are discriminated against for asserting your rights, you may seek assistance from the U.S. Department of Labor, or you may file suit in a federal court.

In any case, the court will decide who will pay court costs and legal fees. If you are successful, the court may order the person you have sued to pay these costs and fees. If you lose, the court may order you to pay these costs and fees, for example, if it finds that your claim is frivolous.

If you have any questions regarding the Plan, please contact the Administrator. If you have any questions about this statement or about your rights under ERISA, you may contact the nearest area office of the Employee Benefits Security Administration (formerly the Pension and Welfare Benefits Administration), U.S. Department of Labor, listed in your telephone directory, or the Division of Technical Assistance and Inquiries, Employee Benefits Security Administration, U.S. Department of Labor, 200 Constitution Avenue, N.W. Washington, D.C. 20210. You also may obtain certain publications about your rights and responsibilities under ERISA by calling the publications hotline of the Employee Benefits Security Administration.

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EXHIBIT A

The “**Severance Benefit**” for a Participant who is the Chief Executive Officer or an executive officer of the Company will include a lump sum cash payment in an amount equal to a number of weeks of Base Pay determined based on the position of the Participant as follows:

Position	Number of Weeks
Chief Executive Officer (CEO)	130
Executive Officers (other than the CEO)	78

Exhibit 10.3

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: November 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: November 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 quarter ended September 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: November 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 quarter ended September 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: November 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.