Bonanza Creek Energy, Inc.
Form 10-Q
August 09, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2018
Commission File Number: 001-35371
Bonanza Creek Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	61-1630631
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

410 17th Street, Suite 1400	
Denver, Colorado	80202
(Address of principal executive offices)	(Zip Code)

(720) 440-6100
(Registrant’s telephone number, including area code)
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes ¨ No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes ¨ No
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 x

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

Emerging growth company ¨ Smaller reporting 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 x 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 Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. x Yes ¨ No

As of August 1, 2018, the registrant had 20,541,070 shares of common stock outstanding.

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements.

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(in thousands, except share amounts)

	Successor June 30, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$21,989	$ 12,711
Accounts receivable:		
Oil and gas sales	38,830	28,549
Joint interest and other	13,926	3,831
Prepaid expenses and other	5,620	6,555
Inventory of oilfield equipment	1,434	1,019
Derivative assets	39	488
Total current assets	81,838	53,153
Property and equipment (successful efforts method):		
Proved properties	552,858	555,341
Less: accumulated depreciation, depletion and amortization	(29,703)	(17,032)
Total proved properties, net	523,155	538,309
Unproved properties	179,735	183,843
Wells in progress	52,747	47,224
Oil and gas properties held for sale, net of accumulated depreciation, depletion and amortization of $2,583 in 2018 (note 4)	82,328	—
Other property and equipment, net of accumulated depreciation of $2,722 in 2018 and $2,224 in 2017	4,488	4,706
Total property and equipment, net	842,453	774,082
Long-term derivative assets	—	6
Other noncurrent assets	3,151	3,130
Total assets	$927,442	$ 830,371
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 5)	$50,242	$ 62,129
Oil and gas revenue distribution payable	20,355	15,667
Derivative liability	28,416	11,423
Total current liabilities	99,013	89,219
Long-term liabilities:		
Credit facility	60,000	—
Ad valorem taxes	19,803	11,584
Long-term derivative liability	4,657	2,972
Asset retirement obligations for oil and gas properties	28,154	38,262
Asset retirement obligations for oil and gas properties held for sale (note 4)	5,386	—
Total liabilities	217,013	142,037

Commitments and contingencies (note 7)		
Stockholders' equity:		
Preferred stock, $.01 par value, 25,000,000 shares authorized, none outstanding	—	—
Common stock, $.01 par value, 225,000,000 shares authorized, 20,534,799 and 20,453,549 issued and outstanding in 2018 and 2017, respectively	4,286	4,286
Additional paid-in capital	692,434	689,068
Retained earnings (deficit)	13,709	(5,020)
Total stockholders' equity	710,429	688,334
Total liabilities and stockholders' equity	$927,442	$ 830,371

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
(UNAUDITED)
(in thousands, except per share amounts)

	Successor		Predecessor
	Three Months Ended June 30, 2018	April 29, 2017 through June 30, 2017	April 1, 2017 through April 28, 2017
Operating net revenues:			
Oil and gas sales	$71,872	$28,114	$ 16,030
Operating expenses:			
Lease operating expense	11,316	6,153	3,203
Gas plant and midstream operating expense	3,247	1,762	836
Gathering, transportation and processing	1,660	—	—
Severance and ad valorem taxes	6,071	2,408	1,352
Exploration	221	359	292
Depreciation, depletion and amortization	9,564	4,836	6,853
Abandonment and impairment of unproved properties	2,477	—	—
General and administrative (including $2,184, $7,949 and $391, respectively, of stock-based compensation)	9,917	16,139	2,998
Total operating expenses	44,473	31,657	15,534
Income (loss) from operations	27,399	(3,543)	496
Other income (expense):			
Derivative loss	(22,012)	—	—
Interest expense	(805)	(195)	(1,088)
Reorganization items, net (note 2)	—	—	97,811
Other income (expense)	277	158	(283)
Total other income (expense)	(22,540)	(37)	96,440
Income (loss) from operations before taxes	4,859	(3,580)	96,936
Income tax benefit (expense)	—	—	—
Net income (loss)	$4,859	$(3,580)	$ 96,936
Comprehensive income (loss)	$4,859	$(3,580)	$ 96,936
Basic net income (loss) per common share	$0.24	$(0.18)	$ 1.88
Diluted net income (loss) per common share	$0.24	$(0.18)	$ 1.85
Basic weighted-average common shares outstanding	20,488	20,369	49,902
Diluted weighted-average common shares outstanding	20,603	20,369	50,486

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS) (UNAUDITED)
(in thousands, except per share amounts)

	Successor		Predecessor
	Six Months Ended June 30, 2018	April 29, 2017 through June 30, 2017	January 1, 2017 through April 28, 2017
Operating net revenues:			
Oil and gas sales	$136,064	$28,114	$ 68,589
Operating expenses:			
Lease operating expense	21,775	6,153	13,128
Gas plant and midstream operating expense	6,860	1,762	3,541
Gathering, transportation and processing	3,998	—	—
Severance and ad valorem taxes	11,303	2,408	5,671
Exploration	250	359	3,699
Depreciation, depletion and amortization	17,072	4,836	28,065
Abandonment and impairment of unproved properties	4,979	—	—
Unused commitments	21	—	993
General and administrative (including $3,192, $7,949 and $2,116, respectively, of stock-based compensation)	19,451	16,139	15,092
Total operating expenses	85,709	31,657	70,189
Income (loss) from operations	50,355	(3,543)	(1,600)
Other income (expense):			
Derivative loss	(30,754)	—	—
Interest expense	(1,162)	(195)	(5,656)
Reorganization items, net (note 2)	—	—	8,808
Other income	290	158	1,108
Total other income (expense)	(31,626)	(37)	4,260
Income (loss) from operations before taxes	18,729	(3,580)	2,660
Income tax benefit (expense)	—	—	—
Net income (loss)	$18,729	$(3,580)	$ 2,660
Comprehensive income (loss)	$18,729	$(3,580)	$ 2,660
Basic net income (loss) per common share	$0.91	$(0.18)	$ 0.05
Diluted net income (loss) per common share	$0.91	$(0.18)	$ 0.05
Basic weighted-average common shares outstanding	20,471	20,369	49,559
Diluted weighted-average common shares outstanding	20,538	20,369	50,971

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (UNAUDITED)
(in thousands, except share amounts)

	Common Stock		Additional Paid-In	Retained Earnings	
	Shares	Amount	Capital	(Deficit)	Total
Balances, December 31, 2017	20,453,549	$ 4,286	$ 689,068	$ (5,020)	$ 688,334
Restricted common stock issued	78,109	—	—	—	—
Restricted stock used for tax withholdings	(24,050)	—	(794)	—	(794)
Exercise of stock options	27,191	—	968	—	968
Stock-based compensation	—	—	3,192	—	3,192
Net income	—	—	—	18,729	18,729
Balances, June 30, 2018	20,534,799	$ 4,286	$ 692,434	$ 13,709	$ 710,429

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)
(in thousands)

	Successor		Predecessor
	Six Months Ended June 30, 2018	April 29, 2017 through June 30, 2017	January 1, 2017 through April 28, 2017
Cash flows from operating activities:			
Net income (loss)	$18,729	$(3,580)	$ 2,660
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	17,072	4,836	28,065
Non-cash reorganization items	—	—	(44,160)
Abandonment and impairment of unproved properties	4,979	—	—
Well abandonment costs and dry hole expense	—	64	2,931
Stock-based compensation	3,192	7,949	2,116
Amortization of deferred financing costs and debt premium	—	—	374
Derivative loss	30,754	—	—
Derivative cash settlements	(11,622)	—	—
Other	172	5	18
Changes in current assets and liabilities:			
Accounts receivable	(20,376)	6,420	(6,640)
Prepaid expenses and other assets	935	270	963
Accounts payable and accrued liabilities	(889)	(19,338)	(5,880)
Settlement of asset retirement obligations	(797)	(459)	(331)
Net cash provided by (used in) operating activities	42,149	(3,833)	(19,884)
Cash flows from investing activities:			
Acquisition of oil and gas properties	(1,295)	(4,982)	(445)
Exploration and development of oil and gas properties	(91,482)	(4,913)	(5,123)
Proceeds from sale of oil and gas properties	20	—	—
Additions to property and equipment - non oil and gas	(280)	(161)	(454)
Net cash used in investing activities	(93,037)	(10,056)	(6,022)
Cash flows from financing activities:			
Proceeds from credit facility	60,000	—	—
Payments to credit facility	—	—	(191,667)
Proceeds from sale of common stock	—	—	207,500
Proceeds from exercise of stock options	968	—	—
Payment of employee tax withholdings in exchange for the return of common stock	(794)	(2,080)	(427)
Net cash provided by (used in) financing activities	60,174	(2,080)	15,406
Net change in cash, cash equivalents and restricted cash	9,286	(15,969)	(10,500)
Cash, cash equivalents and restricted cash:			
Beginning of period	12,782	68,406	78,906
End of period	$22,068	$52,437	$ 68,406
Supplemental cash flow disclosure:			
Cash paid for interest	$906	$193	$ 3,509
Cash paid for reorganization items	$—	$918	$ 52,968

Changes in working capital related to drilling expenditures	$1,909	$8,742	$ 3,360

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

NOTE 1 - ORGANIZATION AND BUSINESS

Bonanza Creek Energy, Inc. (“BCEI” or, together with our consolidated subsidiaries, the “Company”) is engaged primarily in acquiring, developing, exploiting and producing oil and gas properties. The Company's assets and operations are concentrated primarily in the Wattenberg Field in Colorado and in the Dorcheat Macedonia Field in southern Arkansas.

NOTE 2 - BASIS OF PRESENTATION

These unaudited condensed consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) for interim financial statements and pursuant to the rules and regulations of the Securities and Exchange Commission. In the opinion of management, the accompanying unaudited condensed consolidated financial statements reflect all adjustments consisting of normal recurring adjustments as necessary for a fair presentation of our financial position and results of operations. Interim results of operations are not necessarily indicative of the results to be expected for the full fiscal year. As described below, however, prior financial statements are not comparable to our interim financial statements due to the adoption of fresh-start accounting.

The financial information as of December 31, 2017, has been derived from the audited financial statements contained in our Annual Report on Form 10-K for the year ended December 31, 2017 (“2017 Form 10-K”), but does not include all disclosures, including notes required by GAAP. As such, this quarterly report should be read in conjunction with the consolidated financial statements and related notes included in our 2017 Form 10-K. The Company follows the same accounting principles for preparing quarterly and annual reports.

On January 4, 2017, the Company and certain of its subsidiaries (collectively with the Company, the “Debtors”) filed voluntary petitions (the “Bankruptcy Petitions,” and the cases commenced thereby, the “Chapter 11 Cases”) under Chapter 11 of the United States Bankruptcy Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the District of Delaware (the “Bankruptcy Court”) to pursue the Debtors’ Joint Prepackaged Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (as proposed, the “Plan”). The Bankruptcy Court granted the Debtors' motion seeking to administer all of the Debtors' Chapter 11 Cases jointly under the caption In re Bonanza Creek Energy, Inc., et al (Case No. 17-10015). The Debtors received bankruptcy court confirmation of their Plan on April 7, 2017, and emerged from bankruptcy on April 28, 2017 (the “Effective Date”). Although the Company is no longer a debtor-in-possession, the Company was a debtor-in-possession during a portion of the quarter ended June 30, 2017.

Upon emergence from bankruptcy, the Company adopted fresh-start accounting and became a new entity for financial reporting purposes. As a result of the application of fresh-start accounting and the effects of the implementation of the Plan, the Company’s condensed consolidated financial statements after April 28, 2017 are not comparable with the financial statements on or prior to April 28, 2017. The Company's condensed consolidated financial statements and related footnotes are presented with a black line division which delineates the lack of comparability between amounts presented after April 28, 2017 and dates prior thereto.

References to “Successor” or “Successor Company” relate to the financial position and results of operations of the reorganized Company subsequent to April 28, 2017. References to “Predecessor” or “Predecessor Company” relate to the financial position and results of operations of the Company on or prior to April 28, 2017. References to “Current Successor Quarter” and “Current Successor Period” relate to the three and six months ended June 30, 2018, respectively. References to “Prior Successor Quarter” and “Prior Successor Period” relate to the period of April 29, 2017 through June 30, 2017. References to “Prior Predecessor Quarter” relates to the period of April 1, 2017 through April 28, 2017 and “Prior Predecessor Period” relates to the period of January 1, 2017 through April 28, 2017.

Fresh-Start Accounting

The Company adopted fresh-start accounting, pursuant to FASB Accounting Standards Codification (“ASC”) 852, Reorganizations, and applied the provisions thereof to its financial statements with no beginning retained earnings or deficit as of the fresh-start reporting date. The cancellation of all existing shares outstanding on the Effective Date and issuance of new shares of the Successor Company caused a related change of control of the Company under ASC 852.

Under fresh-start accounting, reorganization value represents the fair value of the Successor Company’s total assets and is intended to approximate the amount a willing buyer would pay for the assets immediately after restructuring. Under application of fresh-start accounting, the Company allocated the reorganization value to its individual assets based on their estimated fair values at the date it applied fresh start accounting.

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Reorganization Items, Net

Subsequent to January 4, 2017, and through the date of emergence, all expenses, gains, and losses directly associated with the reorganization were reported as reorganization items, net in the accompanying condensed consolidated statements of operations and comprehensive income (loss) ("accompanying statements of operations"). The following table summarizes reorganization items (in thousands):

Fresh-start related:	
Gain on settlement of liabilities subject to compromise	$412,852
Payment on revolving credit facility fees and remaining unaccrued 2016 STIP	(1,007)
Fresh-start valuation adjustments	(311,361)
Total fresh-start reorganization items, net	$100,484
Prior predecessor quarter professional fees and other	(2,673)
Prior predecessor quarter reorganization items, net	97,811
Prior predecessor period reorganization:	
Legal and professional fees and expenses	(31,662)
Write-off of debt issuance and premium costs	(6,156)
Make-whole payment on Senior Notes	(51,185)
Total prior predecessor period reorganization items, net	$(89,003)
Total reorganization items, net	$8,808

Principles of Consolidation

The balance sheets include the accounts of the Company and its wholly owned subsidiaries, Bonanza Creek Energy Operating Company, LLC, Bonanza Creek Energy Resources, LLC, Bonanza Creek Energy Upstream LLC, Bonanza Creek Energy Midstream, LLC, Holmes Eastern Company, LLC and Rocky Mountain Infrastructure, LLC. All significant intercompany accounts and transactions have been eliminated.

Use of Estimates

The preparation of the Company's condensed consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities at the date of the balance sheet and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Accounting Pronouncements Recently Adopted

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Codification ("ASC") Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASC 606") for the recognition of revenue from contracts with customers. Several additional related updates have been issued since that point. In summary, revenue recognition would occur upon the transfer of promised goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. The guidance also requires enhanced financial statement disclosures over revenue recognition and provisions regarding future revenues and expenses under a gross-versus-net presentation.

The standard is required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with a cumulative adjustment to retained earnings on the opening balance sheet. The standard is effective for annual reporting periods beginning after December 15, 2017, and interim periods within those annual periods. We adopted the new standard on January 1, 2018 and its adoption did not have a significant impact on our financial statements. Please refer to Note 3 - Revenue Recognition for additional discussion.

In January 2016, the FASB issued Update No. 2016-01 - Financial Instruments - Overall to require separate presentation of financial assets and financial liabilities by measurement category and form of financial asset on the balance sheet or the accompanying notes to the financial statements. This authoritative guidance is effective for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. We adopted the new standard on January 1, 2018 and its adoption did not have a material impact on our financial statements and disclosures.

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In August 2016, the FASB issued Update No. 2016-15 - Classification of Certain Cash Receipts and Cash Payments, which clarifies the presentation of specific cash receipts and cash payments within the statement of cash flows. This authoritative accounting guidance is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted. We adopted the new standard on January 1, 2018 and its adoption did not have a material impact on our statements of cash flows and related disclosures.

In November 2016, the FASB issued Update No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash. This update clarifies how entities should present restricted cash and restricted cash equivalents in the statement of cash flows by including them with cash and cash equivalents when reconciling the total beginning and ending amounts for the periods shown on the statement of cash flows. This guidance is to be applied using a retrospective method and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted. We adopted the new standard on January 1, 2018 and the prior period has been adjusted to conform to the current period presentation, which resulted in an increase in cash used in investing activities of $0.1 million for the Prior Predecessor Period.

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the balance sheets that sums to the total of such amounts shown in the accompanying condensed consolidated statements of cash flows (in thousands):

	Successor	
	As of June 30, 2018	As of December 31, 2017
Cash and cash equivalents	$21,989	$ 12,711
Restricted cash included in other noncurrent assets	79	71
Total cash, cash equivalents and restricted cash as shown in the statements of cash flows	$22,068	$ 12,782

Restricted cash consists of funds for road maintenance and repairs.

In January 2017, the FASB issued Update No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business. This update clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This guidance is to be applied using a prospective method and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted. We adopted this new standard on January 1, 2018 and will apply it to any future acquisitions or disposals of assets or business.

In February 2017, the FASB issued Update No. 2017-05, Other Income-Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets. This update is meant to clarify existing guidance and to add guidance for partial sales of nonfinancial assets. This guidance is to be applied using a full retrospective method or a modified retrospective method as outlined in the guidance and is effective at the same time as Update 2014-09, Revenue from Contracts with Customers (Topic 606). We adopted this new standard on January 1, 2018 and its adoption did not have a material impact on our financial statements and disclosures.

In May 2017, the FASB issued Update No. 2017-09 (ASU 2017-09) Compensation - Stock Compensation (Topic 718). The purpose of this update is to provide clarity as to which modifications of awards require modification accounting under Topic 718, whereas previously issued guidance frequently resulted in varying interpretations and a diversity of practice. An entity should employ modification accounting unless the following are met: (1) the fair value of the award is the same immediately before and after the award is modified; (2) the vesting conditions are the same under both the modified award and the original award; and (3) the classification of the modified award is the same as the original award, either equity or liability. Regardless of whether modification accounting is utilized, award disclosure requirements under Topic 718 remain unchanged. This guidance will be effective for annual and interim periods beginning after December 15, 2017. We adopted the new standard on the effective date of January 1, 2018 and its adoption did not have a material impact on our financial statements and disclosures.

Recently Issued Accounting Standards

In February 2016, the FASB issued Update No. 2016-02 – Leases (ASU 2016-02) to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. In January 2018, the FASB issued Update No. 2018-01 Leases (Topic 842) - Land Easement Practical Expedient for Transition to Topic 842, which permits an entity to elect an optional transition practical expedient to not evaluate land easements existing or expiring before the entity's adoption of ASU 2016-02 and not previously accounted for as leases. Furthermore, in July 2018, the FASB issued Update No. 2018-11 (ASU 2018-11): Leases (Topic 842): Targeted Improvements, which provides for another transition method, in addition to the existing transition method, by allowing entities to initially apply the new leases standard at the adoption date (such as January 1, 2019) and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption (i.e. comparative periods presented in the financial statements will continue to be in accordance with current GAAP (Topic 840, Leases)). The standard will be effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted. The Company plans on adopting this guidance on January 1, 2019, using the modified retrospective approach.

In the normal course of business, we enter into operating lease agreements to support our exploration and development operations and lease assets such as drilling rigs, field services, well equipment, pipeline capacity, office space and other assets. Although we continue to assess the impact of the standard on our consolidated financial statements, we believe adoption and implementation will result in an increase in assets and liabilities as well as additional disclosures. We do not expect a material impact on our consolidated statement of operations. We have developed and are executing a project plan, which includes contract review and assessment, as well as evaluation of our systems, processes and internal controls. In addition, we plan to implement new lease accounting software.

There are no other accounting standards applicable to the Company that would have a material effect on the Company's financial statements and disclosures that have been issued, but not yet adopted by the Company as of June 30, 2018, and through the filing date of this report.

NOTE 3 - REVENUE RECOGNITION

On January 1, 2018, the Company adopted ASC 606, using the modified retrospective approach. Results for reporting periods beginning January 1, 2018, are presented in accordance with ASC 606, while prior period amounts are reported in accordance with ASC 605 - Revenue Recognition.

The impact of adoption on our Current Successor Periods results is as follows (in thousands):

	Three Months Ended June 30, 2018		
	As Unadjusted	ASC 606 Adjustments (1)	As Reported
Operating Revenues:			
Oil sales	$60,751	$ —	$ 60,751
Natural gas sales	4,244	694	4,938
NGLs sales	5,217	966	6,183
Oil and gas sales	$70,212	$ 1,660	$ 71,872
Operating expenses:			
Gathering, transportation and processing	$—	$ 1,660	$ 1,660
Net income	$4,859	$ —	$ 4,859

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	Six Months Ended June 30, 2018		
	As Unadjusted	ASC 606 Adjustments (1)	As Reported
Operating Revenues:			
Oil sales	$112,714	$ —	$112,714
Natural gas sales	9,362	1,797	11,159
NGLs sales	9,990	2,201	12,191
Oil and gas sales	$132,066	$ 3,998	$136,064
Operating expenses:			
Gathering, transportation and processing	$—	$ 3,998	$3,998
Net income	$18,729	$ —	$18,729

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

Revenue from Contracts with Customers

Sales of oil, natural gas and natural gas liquids ("NGLs") are recognized when performance obligations are satisfied at the point control of the product is transferred to the customer. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas, and NGLs fluctuates to remain competitive with other available oil, natural gas, and NGLs supplies.

Performance Obligations

Oil Sales

Under our oil sales contracts we sell oil production at the wellhead, or other contractually agreed-upon delivery points, and collect an agreed-upon index price, net of pricing differentials. In this scenario, we recognize revenue when control transfers to the purchaser at the wellhead, or other contractually agreed-upon delivery point, at the net contracted price received.

Natural Gas and NGLs Sales

Under our natural gas processing contracts, we deliver natural gas to an agreed-upon delivery point. The delivery points are specified within each contract, and the transfer of control varies between the inlet and outlet of the midstream processing facility. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGLs and residue gas. For the contracts where we maintain control through the outlet of the midstream processing facility, we recognize revenue on a gross basis, with gathering, transportation and processing fees presented as an expense in our consolidated statements of operations. Alternatively, for those contracts where the Company relinquishes control at the inlet of the midstream processing facility, the Company recognizes natural gas and NGLs revenues based on the contracted amount of the proceeds received from the midstream processing entity and, as a result, we recognize revenue on a net basis.

Working Interest Partners

The Company and its working interest partners have entered into joint operating agreements, which govern the marketing and selling of the working interest partner's share of oil, natural gas and NGLs. When selling oil, natural gas and NGLs on behalf of working interest owners, the Company is acting as an agent and thus reports the revenue on a net basis.

Transaction Price

As noted above, the transaction price is generally tied to a market index, net of adjustments or price differentials, with the variable consideration being the estimation process and related accruals; however, any identified differences between our revenue estimates and actual revenue received historically have not been significant.

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As further described in Note 7 - Commitments and Contingencies, one contract with NGL Crude Logistics, LLP (“NGL”, known as the “NGL agreement”) has an additional aspect of variable consideration related to the minimum volume commitments (“MVCs”) as specified in the agreement. On an on-going basis, the Company performs an analysis of expected risk adjusted production applicable to the NGL agreement based on approved production plans to determine if liquidated damages to NGL are probable. As of June 30, 2018, the Company believes that the volumes delivered to NGL will be in excess of the MVCs required then and for the upcoming approved production plan. As a result of this analysis, to date, no variable consideration related to potential liquidated damages has been considered in the transaction price for the NGL agreement.

Transaction Price Allocated to Remaining Performance Obligations

Under our sales contracts, each unit of product represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and the transaction price for remaining performance obligations is determined in accordance with the preceding section during the period in which the performance obligation is satisfied. For our product sales that have a contract term of one year or less, we applied the practical expedient under the guidance, which states that a Company is not required to disclose 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.

Contract Balances

Under our product sales contracts, we invoice customers once our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our product sales contracts do not give rise to contract assets or liabilities under this guidance. At June 30, 2018 and December 31, 2017, our receivables from contracts with customers were $38.8 million and $28.5 million, respectively.

Prior-Period Performance Obligations

We record revenue in the month production is delivered to the purchaser. However, settlement statements for certain natural gas and NGLs sales may not be received for 30 to 60 days after the date production is delivered, and as a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts received for product sales in the month in which payment is received from the purchaser. We have existing internal controls for our revenue estimation process and related accruals, and any identified differences between our revenue estimates and actual revenue received historically have not been significant. For the period from January 1, 2018 through June 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

NOTE 4 - ASSETS HELD FOR SALE

During the first quarter of 2018, the Company established a plan to sell all of the Company's assets within its Mid-Continent region and North Park Basin, at which point they were deemed held for sale.

The Company sold its North Park Basin on March 9, 2018 for minimal net proceeds and full release of all current and future obligations resulting in a minimal net loss. As of December 31, 2017, the assets within the Company's North Park Basin represented $5.4 million, net of accumulated depreciation, depletion and amortization; and a corresponding asset retirement obligation liability of approximately $5.4 million.

As of June 30, 2018, the Company had $82.3 million of oil and gas properties held for sale, net of $2.6 million accumulated depreciation, depletion and amortization as presented in the accompanying condensed consolidated balance sheets (“accompanying balance sheets”). These properties consist of all assets within the Company's Mid-Continent region. There is a corresponding asset retirement obligation liability of approximately $5.4 million in the asset retirement obligations for oil and gas properties held for sale in the accompanying balance sheets. There were no other material assets or liabilities associated with the assets held for sale.

On August 6, 2018, the Company entered into an agreement to simultaneously close and divest of its assets within its Mid-Continent region for $117.0 million, subject to customary purchase price adjustments.

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NOTE 5 - ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses contain the following (in thousands):

	Successor	
	As of June 30, 2018	As of December 31, 2017
Drilling and completion costs	$23,742	$ 21,833
Accounts payable trade	10,326	6,256
Accrued general and administrative cost	3,111	10,025
Lease operating expense	4,039	5,005
Accrued interest	506	250
Accrued oil and gas hedging	2,325	808
Production and ad valorem taxes and other	6,193	17,952
Total accounts payable and accrued expenses	$50,242	$ 62,129

NOTE 6 - LONG-TERM DEBT

Long-term debt consisted of the following (in thousands):

	Successor	
	As of June 30, 2018	As of December 31, 2017
Credit facility	$60,000	$ —
Total long-term debt	$60,000	$ —

Credit Facility

Upon emergence from bankruptcy, the Company entered into a new revolving credit facility, as the borrower, with KeyBank National Association, as the administrative agent, and certain lenders party thereto (the “credit facility”). The borrowing base of $191.7 million is redetermined semiannually, as early as April and October of each year. Effective May 31, 2018, the credit facility's $191.7 million borrowing base was reaffirmed, at the request of the Company, and certain provisions related to the disposition of assets of the Company to provide the Company with greater flexibility to participate in asset swaps was adjusted.

The credit facility restricts, among other items, certain dividend payments, additional indebtedness, purchase of margin stock, asset sales, loans, investments and mergers. The credit facility also contains certain financial covenants, which require the maintenance of certain financial and leverage ratios, as defined by the credit facility. The credit facility states that the Company's leverage ratio of indebtedness to earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense and other non-cash charges (“EBITDAX”) is not to exceed 3.50 to 1.00. The Company must maintain a minimum current ratio of 1.00 to 1.00 and a minimum interest coverage ratio of trailing twelve-month EBITDAX to trailing twelve-month interest expense of 2.50 to 1.00 as of the end of the respective fiscal quarter. As of June 30, 2018, and through the filing date of this report, the Company was in compliance with all financial and non-financial covenants of the credit facility.

The credit facility provides for interest rates plus an applicable margin to be determined based on London Interbank Offered Rate (“LIBOR”) or a base rate, at the Company’s election. LIBOR borrowings bear interest at LIBOR, plus a margin of 3.00% to 4.00% depending on the utilization level, and the base rate borrowings bear interest at the “Reference Rate,” as defined in the credit facility, plus a margin of 2.00% to 3.00% depending on the utilization level.

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NOTE 7 - COMMITMENTS AND CONTINGENCIES

Legal Proceedings

From time to time, the Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. The Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its condensed consolidated financial statements. In accordance with accounting authoritative guidance, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the most likely anticipated outcome or the minimum amount within a range of possible outcomes. Because legal proceedings are inherently unpredictable and unfavorable resolutions could occur, assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies, the Company may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, and/or the ongoing discovery and development of information important to the matters. The Company regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. No claims have been made, nor is the Company aware of any material uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration or the violation of any rules or regulations. As of the filing date of this report, there were no material pending or overtly threatened legal actions against the Company of which it is aware.

As previously described in our 2017 Form 10-K, the Company and the Colorado Department of Public Health and Environment (“CDPHE”) agreed to a Compliance Order on Consent (the “COC”) resolving the matters addressed by a compliance advisory issued to the Company for certain storage tank facilities located in the Wattenberg Field with respect to applicable air quality regulations. Pursuant to the terms of the COC, the Company paid an administrative penalty of $0.2 million in 2017. The Company must also adopt procedures and processes to address the monitoring, reporting, and control of air emissions. The COC further sets forth compliance requirements and criteria for continued operations and contains provisions regarding record-keeping, modifications to the COC, circumstances under which the COC may terminate with respect to certain wells and facilities, and the sale or transfer of operational or ownership interests covered by the COC. In order to be in compliance, the Company incurred $0.7 million in 2017, and currently anticipates spending $3.5 million in 2018, and $3.1 million for 2019 through 2022. The COC can be terminated after four years with a showing of substantial compliance and CDPHE approval.

Commitments

The purchase agreement to deliver fixed determinable quantities of crude oil to NGL became effective on April 28, 2017. The terms of the NGL agreement includes defined volume commitments over an initial seven-year term. Under the terms of the NGL agreement, the Company will be required to make periodic deficiency payments for any shortfalls in delivering minimum volume commitments, which are set in six-month periods beginning in January 2018. There were no minimum volume commitments for the year ending December 31, 2017. During 2018, the average minimum volume commitment will be approximately 10,100 barrels per day, and the minimum volume commitment increases by approximately 41% from 2018 to 2019 and approximately 3% each year thereafter for the remainder of the contract, to a maximum of approximately 16,000 barrels per day. The aggregate financial commitment fee over the remaining term, based on the minimum volume commitment schedule (as defined in the agreement) and the applicable differential fee, is $145.5 million as of June 30, 2018. Upon notifying NGL at least twelve months prior to the expiration date of the NGL agreement, the Company may elect to extend the term of the NGL agreement for up to three additional years.

On April 29, 2017, the Company entered into a new office lease agreement to rent office facilities. The lease is non-cancelable and expires in February 2022.

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The annual minimum commitment payments under the NGL agreement and the office lease for the next five years as of June 30, 2018 are presented below (in thousands):

	NGL Commitments[1]	Office Lease Commitments	Total
2018	$ 6,664	$—	$6,664
2019	22,176	1,224	23,400
2020	27,949	1,335	29,284
2021	28,791	1,423	30,214
2022	29,485	240	29,725
2023 and thereafter	30,448	—	30,448
Total	$ 145,513	$4,222	$149,735

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(1) The above calculation is based on the minimum volume commitment schedule (as defined in the NGL agreement) and applicable differential fees.

There have been no other material changes from the commitments disclosed in the notes to the Company's consolidated financial statements included in our 2017 Form 10-K.

NOTE 8 - STOCK-BASED COMPENSATION

2017 Long Term Incentive Plan

Upon emergence from bankruptcy, the Company adopted a new Long Term Incentive Plan (the "2017 LTIP"), as established by the pre-emergence Board, which allows for the issuance of restricted stock units ("RSUs"), performance stock units ("PSUs") and options. See below for further discussion of awards granted under the 2017 LTIP.

Restricted Stock Units

The 2017 LTIP, established by the pre-emergence Board, allows for the issuance of RSUs to members of the Board of Directors and employees of the Company at the discretion of the Board of Directors. Each RSU represents one share of the Company's common stock to be released from restriction upon completion of the vesting period. The awards typically vest in one-third increments over three years. The RSUs are valued at the grant date share price and are recognized as general and administrative expense over the vesting period of the award.

The Company granted 343,574 RSUs with a fair value of $9.5 million during the Current Successor Period. Total expense recorded for RSUs, inclusive of grants to the members of the Board of Directors, for the Current Successor Period was $2.4 million. As of June 30, 2018, unrecognized compensation cost was $13.0 million and will be amortized through 2023.

A summary of the status and activity of non-vested restricted stock units for the Current Successor Period is presented below:

	Restricted Stock Units	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	261,165	$ 34.93
Granted	343,574	$ 27.56
Vested	(78,109)	$ 34.36
Forfeited	(38,073)	$ 30.88
Non-vested at end of quarter	488,557	$ 30.15

Performance Stock Units

The 2017 LTIP, established by the pre-emergence Board, allows for the issuance of PSUs to employees at the sole discretion of the Board of Directors. The number of shares of the Company's common stock that may be issued to settle PSUs range from zero to two times the number of PSUs awarded. The PSUs vest in their entirety at the end of the three-year performance period. The total number of PSUs granted is evenly split between two performance criterion. The first criterion is based on a comparison of the Company's absolute and relative total shareholder return ("TSR") for the performance period

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compared with the TSRs of a group of peer companies for the same performance period. The second criterion is based on the Company's average annual return on capital employed (“ROCE”) for each year during the three-year performance period. The TSR for the Company and each of the peer companies is determined by dividing (A)(i) the volume-weighted average share price for the last 30 trading days of the performance period, minus (ii) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period, by (B) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period. Compensation expense associated with PSUs is recognized as general and administrative expense over the performance period.

The fair value of the PSUs was measured at the grant date with a stochastic process method using a Brownian Motion simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company’s PSUs, the Company could not predict with certainty the path its stock price or the stock prices of its peers would take over the performance period. By using a stochastic simulation, the Company created multiple prospective stock pathways, statistically analyzed these simulations, and ultimately made inferences regarding the most likely path the stock price would take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the Brownian Motion Model, was deemed an appropriate method by which to determine the fair value of the portion of the PSUs tied to the TSR. Significant assumptions used in this simulation include the Company’s expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the performance period, as well as the volatilities for each of the Company’s peers.

During the Current Successor Quarter, the Company granted 59,641 PSUs to certain officers with a fair value of $1.8 million. The Company recognized compensation expense of $0.1 million for the Current Successor Quarter. As of June 30, 2018, unrecognized compensation cost was $1.7 million and will be amortized through 2020.

The following table presents the assumptions used to determine the fair value of the portion of the PSUs tied to TSR that were granted during the Current Successor Quarter:

	For the Three Months Ended June 30, 2018
Expected term of award (in years)	3
Risk-free interest rate	2.76 %
Expected daily volatility	2.6 %

A summary of the status and activity of performance stock units for the Current Successor Period is presented below:

	Performance Stock Units	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	—	$ —
Granted [1]	59,641	$ 29.92
Vested	—	$ —
Non-vested at end of quarter [1]	59,641	$ 29.92

(1) The number of awards assumes that the associated performance condition is met at the target amount. The final number of shares of the Company’s common stock issued may vary depending on the performance multiplier, which ranges from zero to two, depending on the level of satisfaction of the performance condition.

Stock Options

The 2017 LTIP, established by the pre-emergence Board, allows for the issuance of stock options to the Company's employees at the sole discretion of the Board of Directors. Options expire ten years from the grant date unless otherwise determined by the Board of Directors. Compensation expense on the stock options are recognized as general and administrative expense over the vesting period of the award.

There were no stock options granted during the Current Successor Quarter. Total expense recorded for stock options for the Current Successor Quarter was $0.7 million. As of June 30, 2018, unrecognized compensation cost was $1.6 million and will be amortized through 2020.

A summary of the status and activity of non-vested stock options for the Current Successor Period is presented below:

	Stock Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at beginning of year	197,271	$ 34.36	9.3	$ —
Granted	—	—	—	$ —
Exercised	(27,191)	34.36	—	$ —
Forfeited	(19,083)	34.36	—	$ —
Outstanding at end of quarter	150,997	$ 34.36	8.5	$ —

A summary of additional information related to options outstanding and exercisable as of June 30, 2018 is presented below:

Exercise Price	Number of Options Outstanding and Exercisable	Weighted-Average Remaining Contractual Life (in years)
$34.36	50,811	8.3

NOTE 9 - FAIR VALUE MEASUREMENTS

The Company follows fair value measurement authoritative guidance, which defines fair value, establishes a framework for using fair value to measure assets and liabilities, and expands disclosures about fair value measurements. The authoritative accounting guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The statement establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company’s assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities

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

Level 3: Significant inputs to the valuation model are unobservable

Financial and non-financial assets and liabilities are to be classified based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables present the Company's financial and non-financial assets and liabilities that were accounted for at fair value as of June 30, 2018 and December 31, 2017 and their classification within the fair value hierarchy (in thousands):

	As of June 30, 2018		
	Level 1	Level 2	Level 3
Derivative assets(1)	$—	$39	$—
Derivative liabilities(1)	$—	$33,073	$—
Unproved properties(2)	$—	$—	$179,735

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	As of December 31, 2017		
	Level 1	Level 2	Level 3
Derivative assets(1)	$—	$494	$—
Derivative liabilities(1)	$—	$14,395	$—
Asset retirement obligations(3)	$—	$—	$8,481

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis

(2) Represents non-financial assets that are measured at fair value on a nonrecurring basis. Please refer to the Unproved Oil and Gas Properties sections below for additional discussion.

(3) Represents the revision to estimates of the asset retirement obligation, which is a non-financial liability that is measured at fair value on a nonrecurring basis. Please refer to the Asset Retirement Obligation section below for additional discussion.

Unproved Oil and Gas Properties

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be fully recoverable. To measure the fair value of unproved properties, the Company uses Level 3 inputs and the income valuation technique, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, remaining lease life, standard amortization and estimated reserve values. The Company impaired non-core acreage in the Wattenberg Field due to leases expiring, which had a carrying value of $184.7 million, to their fair value of $179.7 million, and recognized an impairment of unproved properties for the Current Successor Period of $5.0 million.

Asset Retirement Obligation

The Company utilizes the income valuation technique to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company’s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Upon completion of wells and natural gas plants, the Company records an asset retirement obligation at fair value using Level 3 assumptions. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations measured at fair value as of June 30, 2018. The Company had $8.5 million of asset retirement obligations recorded at fair value as of December 31, 2017.

Long-term Debt

The Company's credit facility approximates fair value as the applicable interest rates are floating. The outstanding balance under the credit facility as of June 30, 2018 was $60.0 million.

NOTE 10 - ASSET RETIREMENT OBLIGATIONS

The Company recognizes an estimated liability for future costs to abandon its oil and gas properties. The fair value of the asset retirement obligation is recorded as a liability when incurred, which is typically at the time the asset is acquired or placed in service. There is a corresponding increase to the carrying value of the asset which is included in the proved properties line item in the accompanying balance sheets. The Company depletes the amount added to proved properties and recognizes expense in connection with accretion of the discounted liability over the remaining estimated economic lives of the properties.

The Company’s estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimated costs to abandon the wells, and regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred, which ranges from 5% to 7%.

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A roll-forward of the Company's asset retirement obligation is as follows (in thousands):

Beginning balance as of December 31, 2017	$38,262
Liabilities settled	(383)
Additions	226
Accretion expense	912
Sold properties	(5,477)
Ending balance as of June 30, 2018[(1)]	$33,540

(1) Includes $5.4 million of asset retirement obligations associated with assets held for sale.

NOTE 11 - DERIVATIVES

The Company enters into commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. All contracts are entered into for other-than-trading purposes. The Company’s derivatives include swaps, collar arrangements, and basis swaps for oil and natural gas, and none of the derivative instruments qualifies as having hedging relationships.

In a typical commodity swap agreement, if the agreed upon published third-party index price is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference.

A cashless collar arrangement establishes a floor and ceiling price on future oil and gas production. When the settlement price is above the ceiling price, the Company pays the difference between the settlement price and the ceiling price. When the settlement price is below the floor price, the Company receives the difference between the settlement price and floor price.

A basis swap arrangement guarantees a price differential from a specified delivery point. The Company receives the difference between the price differential and the stated terms, if the price differential is greater than the stated terms. The Company pays the difference between the price differential and the stated terms, if the stated terms are greater than the price differential.

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As of June 30, 2018, the Company had entered into the following commodity derivative contracts:

	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu
Q318				
Cashless Collar	2,000	$43.00/$53.50	13,600	$2.75/$3.32
Swap	5,000	$57.87	—	—
Q418				
Cashless Collar	2,000	$43.00/$53.50	12,600	$2.75/$3.35
Swap	5,000	$58.07	—	—
Q119				
Cashless Collar	2,000	$43.00/$54.53	7,600	$2.75/$3.22
Swap	5,000	$59.33	—	—
Q219				
Cashless Collar	3,330	$51.81/$64.23	2,505	$2.75/$3.22
Swap	4,500	$58.32	—	—
Q319				
Swap	3,000	$55.00	—	—
Q419				
Swap	3,000	$55.00	—	—

Subsequent to quarter-end, the Company entered into a natural gas basis swap between NYMEX Henry Hub price and the Colorado Interstate Gas (CIG) Rockies Natural Gas price, the index on which the majority of our natural gas is sold.

As of the filing date of this report, the Company had entered into the following commodity derivative contracts:

	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)		Natural Gas (NYMEX Henry Hub)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu	MMBtu/day	Weighted Avg. Basis Differential to NYMEX Henry Hub Price per MMBtu
Q318						
Cashless Collar	2,000	$43.00/$53.50	13,600	$2.75/$3.32	—	—
Swap	5,000	$57.87	—	—	—	—
Basis Swap	—	—	—	—	8,354	$0.670
Q418						
Cashless Collar	2,000	$43.00/$53.50	12,600	$2.75/$3.35	—	—
Swap	5,000	$58.07	—	—	—	—
Basis Swap	—	—	—	—	12,600	$0.670
Q119						
Cashless Collar	2,000	$43.00/$54.53	7,600	$2.75/$3.22	—	—
Swap	5,000	$59.33	—	—	—	—
Basis Swap	—	—	—	—	7,600	$0.665
Q219						
Cashless Collar	3,330	$51.81/64.23	2,505	$2.75/$3.22	—	—
Swap	4,500	$58.32	—	—	—	—
Q319						
Swap	3,000	$55.00	—	—	—	—

Q419						
Swap	3,000	$55.00	—	—	—	—

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Derivative Assets Fair Value

The Company’s commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities.

The following table contains a summary of all the Company’s derivative positions reported on the accompanying balance sheets as of June 30, 2018 and December 31, 2017 (in thousands):

	Balance Sheet Location	Successor As of June 30, 2018 Fair Value	As of December 31, 2017 Fair Value
Derivative Assets:			
Commodity contracts	Current assets	$39	$488
Commodity contracts	Noncurrent assets	—	6
Derivative Liabilities:			
Commodity contracts	Current liabilities	(28,416)	(11,423)
Commodity contracts	Long-term liabilities	(4,657)	(2,972)
Total derivative liabilities, net		$(33,034)	$(13,901)

The Company had not entered into any derivative contracts as of June 30, 2017. The following table summarizes the components of the derivative loss presented on the accompanying statements of operations for the periods below (in thousands):

	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
Derivative cash settlement gain (loss):		
Oil contracts	$(7,319)	$(11,825)
Gas contracts	9	203
Total derivative cash settlement loss(1)	$(7,310)	$(11,622)
Change in fair value loss	$(14,702)	$(19,132)
Total derivative loss(1)	$(22,012)	$(30,754)

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(1) Total derivative loss and total derivative cash settlement loss for the Current Successor Quarter and Current Successor Period are reported in the derivative loss line item and derivative cash settlements line item in the accompanying condensed consolidated statements of cash flows, within cash flows from operating activities.

NOTE 12 - EARNINGS PER SHARE

The Company issues RSUs, which represent the right to receive, upon vesting, one share of the Company's common stock. The number of potentially dilutive shares related to RSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the vesting period. The Company issued PSUs, which represent the right to receive, upon settlement of the PSUs, a number of shares of the Company's common stock that range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the performance period applicable to such PSUs. The Company issued stock options and warrants, which both represent the right to purchase the Company's common stock at a specified price. The number of potentially dilutive shares related to the stock options is based on the number of shares, if any, that would be exercised at the end of the respective reporting period, assuming that date was the end of such stock options' term. The number of potentially dilutive shares related to the warrants is based on the number of shares, if any, that would be exercisable at the end of the respective reporting period. Please refer to Note 8 - Stock-Based Compensation for additional discussion.

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The RSUs, PSUs, stock options, and warrants of the Company are all non-participating securities, and therefore, the Company used the treasury stock method to calculate earnings per share as shown in the following table (in thousands, except per share amounts):

	Successor		
	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018	April 29, 2017 through June 30, 2017
Net income (loss)	$4,859	$18,729	$(3,580)
Basic net income (loss) per common share	$0.24	$0.91	$(0.18)
Diluted net income (loss) per common share	$0.24	$0.91	$(0.18)
Weighted-average shares outstanding - basic	20,488	20,471	20,369
Add: dilutive effect of contingent stock awards	115	67	—
Weighted-average shares outstanding - diluted	20,603	20,538	20,369

There were 181,762 and 196,435 dilutive shares that were anti-dilutive for the Current Successor Quarter and Current Successor Period, respectively. The Company was in a net loss position for the Prior Successor Quarter, which made any potentially dilutive shares anti-dilutive. There were 717,201 anti-dilutive shares in the Prior Successor Quarter.

The Predecessor Company issued shares of restricted stock, which entitled the holders to receive non-forfeitable dividends, if and when the Predecessor Company was to declare a dividend, before vesting, thus making the awards participating securities. The awards are included in the calculation of earnings per share under the two-class method. The two-class method allocates earnings for the period between common shareholders and unvested participating shareholders, and allocates losses to common shareholders only.

The Predecessor Company issued performance stock units (“PSUs”), which represented the right to receive, upon settlement of the PSUs, a number of shares of the Predecessor Company’s common stock that range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the measurement period applicable to such PSUs.

The Predecessor Company issued restricted stock, which are participating securities, and PSUs, and therefore, the Company used the two-class method to calculate earnings per share as shown in the following table (in thousands, except per share amounts):

	Predecessor	
	April 1, 2017 through April 28, 2017	January 1, 2017 through April 28, 2017
Net income	$96,936	$ 2,660
Less: undistributed income to unvested restricted stock	3,346	120
Undistributed income to common shareholders	93,590	2,540
Basic net income per common share	$1.88	$ 0.05
Diluted net income per common share	$1.85	$ 0.05
Weighted-average shares outstanding - basic	49,902	49,559

Add: dilutive effect of contingent stock awards	584	1,412
Weighted-average shares outstanding - diluted	50,486	50,971

There were 188,278 and 258,126 anti-dilutive shares in the Prior Predecessor Quarter and Prior Predecessor Period, respectively. The participating shareholders are not contractually obligated to share in the losses of the Company; therefore, the entire net loss is allocated to the outstanding common shareholders.

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NOTE 13 - INCOME TAXES

On December 22, 2017, the U.S. Congress enacted the Tax Cuts and Jobs Act, which made significant changes to U.S. federal income tax law, including a reduction in the federal corporate tax rate to 21%, effective January 1, 2018. In accordance with U.S. GAAP, we recognized the effect of the rate change on deferred tax assets and liabilities as of December 31, 2017.

The Company uses the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. Deferred tax assets or liabilities at the end of each period are determined using the tax rate in effect at that time. There is a full valuation allowance on the Company's net deferred tax asset causing the Company’s current rate to differ from the U.S. statutory income tax rate.

As of June 30, 2018, the Company had no unrecognized tax benefits. The Company’s management does not believe that there are any new items or changes in facts or judgments that would impact the Company's tax position taken thus far in 2018.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our Annual Report on Form 10-K for the year ended December 31, 2017, as well as the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

Executive Summary

We are a Denver-based exploration and production company focused on the extraction of oil and associated liquids-rich natural gas in the United States. Our oil and liquids-weighted assets are concentrated primarily in the Wattenberg Field in Colorado and the Dorcheat Macedonia Field in southern Arkansas.

Chief Executive Officer Appointment

Effective April 11, 2018, the Company appointed Eric T. Greager as the new President and Chief Executive Officer of the Company. Mr. Greager has over 20 years of experience in the oil and gas industry, including exposure to both the operating and technical aspects of the industry.

Mr. Greager, 47, previously served as a Vice President and General Manager at Encana Oil & Gas (USA) Inc. Mr. Greager joined Encana in 2006, and served in various management and executive positions, including as a member of the boards of directors of Encana Procurement Inc. and Encana Oil & Gas (USA) Inc. Mr. Greager previously served on the board of directors of Western Energy Alliance and the board of managers of Hunter Ridge Energy Services. Mr. Greager received his Master's Degree in Economics from the University of Oklahoma and his Bachelor's Degree in Engineering from the Colorado School of Mines.

Bankruptcy Proceedings under Chapter 11

On January 4, 2017, the Company filed for Chapter 11 in the Bankruptcy Court. The Company received bankruptcy court confirmation of its Plan on April 7, 2017, and emerged from bankruptcy on April 28, 2017, the Effective Date. Upon emergence from bankruptcy, the Company adopted fresh-start accounting and became a new entity for financial reporting purposes. Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date, which differed materially from the recorded values of those same assets and liabilities in the Predecessor Company. The lack of comparability between amounts presented after April 28, 2017 and dates prior thereto are presented with a black line division.

Outlook for 2018

The Company is accelerating its Wattenberg development program while testing enhanced completion designs on large-scale pads throughout the Company's acreage position, including delineating its French Lake leasehold. The program contemplates running one rig in the first half of 2018 with a second rig added during the third quarter of 2018. The 2018 program is expected to grow Wattenberg annual production by approximately 20% in 2018 and greater than 50% in 2019, assuming a continuous two rig program. Allocated capital associated with this program is expected to be approximately $275.0 million to $295.0 million, which will support drilling 77 gross wells and turning online 49 gross wells in 2018.

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Results of Operations

The Company conducted standard business operations throughout the bankruptcy proceedings and during the application of fresh-start accounting, resulting in specific financial statement line items following normal course of business trends. The trends associated with the non-impacted financial statement line items are explained throughout the results of operations and include revenues, lease operating expense, gas plant and midstream operating expense, severance and ad valorem taxes, and exploration expense. The financial statement line items that were specifically impacted by the bankruptcy proceedings and application of fresh-start accounting are discussed within the confines of the presented periods and include depreciation, depletion and amortization, general and administrative expense, interest expense, and reorganization items, net.

The following table summarizes our revenues, sales volumes, and average sales prices for the periods indicated:

	Successor		Predecessor
	Three Months Ended June 30, 2018	April 29, 2017 through June 30, 2017	April 1, 2017 through April 28, 2017
Revenues:			
Crude oil sales[1]	$60,640	$21,016	$11,738
Natural gas sales[2]	4,629	3,606	2,075
Natural gas liquids sales [3]	6,183	3,237	2,082
Product revenue	$71,452	$27,859	$15,895
Sales Volumes:			
Crude oil (MBbls)	952.4	484.3	246.7
Natural gas (MMcf)	2,177.8	1,557.2	828.0
Natural gas liquids (MBbls)	324.6	209.5	108.8
Crude oil equivalent (MBoe)[3]	1,640.0	953.4	493.5
Average Sales Prices (before derivatives)[4]:			
Crude oil (per Bbl)	$63.67	$43.39	$47.58
Natural gas (per Mcf)	$2.13	$2.32	$2.51
Natural gas liquids (per Bbl)	$19.05	$15.45	$19.13
Crude oil equivalent (per Boe)[3]	$43.57	$29.22	$32.21
Average Sales Prices (after derivatives)[4]:			
Crude oil (per Bbl)	$55.99	$43.39	$47.58
Natural gas (per Mcf)	$2.13	$2.32	$2.51
Natural gas liquids (per Bbl)	$19.05	$15.45	$19.13
Crude oil equivalent (per Boe)[3]	$39.11	$29.22	$32.21

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(1) Crude oil sales excludes $0.1 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the Current Successor Quarter and the Prior Successor Quarter. There were no oil transportation revenues from third parties for the Prior Predecessor Quarter.

(2) Natural gas sales excludes $0.3 million, $0.2 million and $0.1 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the Current Successor Quarter, Prior Successor Quarter and Prior Predecessor Quarter, respectively.

(3) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.

(4) The derivatives economically hedge the price we receive for crude oil and natural gas. For the Current Successor Quarter, the derivative cash settlement loss for oil contracts was $7.3 million. Please refer to Note 11 - Derivatives of Part I, Item 1 of this report for additional disclosures.

Revenues increased for the Current Successor Quarter by 63%, to $71.5 million, compared to $43.8 million for the combined Prior Successor and Predecessor Quarter, due to a combination of a 44% increase in oil equivalent pricing and a 30% increase in oil sales volumes. In addition to the overall increase due to operations, there was an increase of $1.7 million related

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to the adoption of ASC 606, which caused certain revenues to be shown gross compared to a historical net presentation. Please refer to Note 3 - Revenue Recognition of Part I, Item 1 of this report for additional information.

The following table summarizes our operating expenses for the periods indicated:

	Successor		Predecessor
	Three Months Ended June 30, 2018	April 29, 2017 through June 30, 2017	April 1, 2017 through April 28, 2017
Expenses:			
Lease operating expense	$11,316	$6,153	$3,203
Gas plant and midstream operating expense	3,247	1,762	836
Gathering, transportation and processing	1,660	—	—
Severance and ad valorem taxes	6,071	2,408	1,352
Exploration	221	359	292
Depreciation, depletion and amortization	9,564	4,836	6,853
Abandonment and impairment of unproved properties	2,477	—	—
General and administrative	9,917	16,139	2,998
Operating Expenses	$44,473	$31,657	$15,534
Selected Costs ($ per Boe):			
Lease operating expense	$6.90	$6.45	$6.49
Gas plant and midstream operating expense	1.98	1.85	1.69
Gathering, transportation and processing	1.01	—	—
Severance and ad valorem taxes	3.70	2.53	2.74
Exploration	0.13	0.38	0.59
Depreciation, depletion and amortization	5.83	5.07	13.89
Abandonment and impairment of unproved properties	1.51	—	—
General and administrative	6.05	16.93	6.07
Operating Expenses	$27.11	$33.21	$31.47

Lease operating expense. Our lease operating expense increased $2.0 million, or 21%, to $11.3 million for the Current Successor Quarter from $9.4 million for the combined Prior Successor and Predecessor Quarter, and increased on an equivalent basis per Boe by 7%. The Company experienced a $0.4 million increase in pumping and gauging charges, $0.4 million increase in well servicing charges, and $0.7 million increase in compression charges during the Current Successor Quarter when compared to the combined Prior Successor and Predecessor Quarter. The increase in costs is largely associated with the accelerated schedule of compressor exchanges within our Rocky Mountain region.

Gas plant and midstream operating expense. Our gas plant and midstream operating expense increased $0.6 million, or 25%, to $3.2 million for the Current Successor Quarter from $2.6 million for the combined Prior Successor and Predecessor Quarter. Gas plant and midstream operating expense per Boe increased 10% during the comparable periods due to the costs associated with the accelerated schedule of compressor exchanges within our Rocky Mountain Infrastructure gathering systems.

Gathering, transportation and processing. As noted in the operating revenues section above, the increase in gathering, transportation and processing expense during the Current Successor Quarter to $1.7 million is related to the Company's adoption of ASC 606 during the Current Successor Period, which caused certain revenues to be shown gross, with the related expenses recorded in this line item. Please refer to Note 3 - Revenue Recognition of Part I, Item 1 of this report for additional information.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased 61% to $6.1 million for the Current Successor Quarter from $3.8 million for the combined Prior Successor and Predecessor Quarter. Severance and ad valorem taxes primarily correlate to revenues, which increased 63% over the comparable period.

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Exploration. Our exploration expense for the Current Successor Quarter, Prior Successor Quarter, and Prior Predecessor Quarter consisted primarily of delay lease rental payments.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense per Boe was $5.83, $5.07 and $13.89 for the Current Successor Quarter, Prior Successor Quarter, and Prior Predecessor Quarter, respectively. The Prior Successor Quarter reflects the $310.6 million fair value downward adjustment to the depletable asset base upon adoption of fresh-start accounting. The Current Successor Quarter excludes depreciation, depletion and amortization on the assets held for sale. The increase in depreciation, depletion and amortization during the Current Successor Quarter when compared to the Prior Successor Quarter primarily correlates to an increase in capital expenditures.

Abandonment and impairment of unproved properties. The Company incurred $2.5 million of impairment charges due to the standard amortization of unproved properties within the Wattenberg Field during the Current Successor Quarter. There were no abandonment and impairment of unproved properties during the Prior Successor and Predecessor Quarters.

General and administrative. Our general and administrative expense decreased by $9.2 million to $9.9 million for the Current Successor Quarter from $19.1 million for the combined Prior Successor and Predecessor Quarter. On a per Boe basis, our general and administrative expense was $6.05 in the Current Successor Quarter as compared to $13.23 in the combined Prior Successor and Predecessor Quarter. The Prior Successor Quarter reflects a one-time $7.1 million non-cash stock-based compensation charge from the vesting of the Company's former Chief Executive Officer's stock awards upon separation from the Company. The incremental decrease in general and administrative expense during the Current Successor Quarter when compared to the combined Prior Successor and Predecessor Quarter, is due to a $1.1 million decrease in salaries and benefits due to workforce reductions and a $1.0 million decrease in restructuring fees.

Derivative loss. Our derivative loss for the Current Successor Quarter was $22.0 million. We had no derivative contracts during the Prior Successor and Predecessor Quarters. Our derivative loss is due to settlements and fair market value adjustments caused by market prices being higher than our contracted hedge prices. Please refer to Note 11 - Derivatives of Part I, Item 1 of this report for additional discussion.

Interest expense. Our interest expense for the Current Successor Quarter, the Prior Successor Quarter, and the Prior Predecessor Quarter was $0.8 million, $0.2 million, and $1.1 million, respectively. Upon filing its petition for Chapter 11, the Company ceased accruing interest expense on its Senior Notes. The Company incurred $0.6 million in interest expense associated with the credit facility and $0.2 million in commitment fees on the available borrowing base under the credit facility during the Current Successor Quarter. The Company incurred $0.2 million in commitment fees on the available borrowing base under the credit facility during the Prior Successor Quarter. The interest expense incurred during the Prior Predecessor Quarter relates to the predecessor credit facility. Average debt outstanding for the Current Successor Quarter and the Prior Predecessor Quarter was $45.6 million and $305.1 million, respectively. The Company had no outstanding debt for the Prior Successor Quarter.

Reorganization items, net. The Company incurred significant costs associated with the reorganization. Our reorganization income was $97.8 million for the Prior Predecessor Quarter. Upon adoption of fresh-start accounting, the Company incurred a $412.9 million gain on the settlement of liabilities subject to compromise, a $311.4 million loss on fresh-start valuation adjustments, and $3.7 million for professional fees and other charges.

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The following table summarizes our revenues, sales volumes, and average sales prices for the periods indicated:

	Successor		Predecessor
	Six Months Ended June 30, 2018	April 29, 2017 through June 30, 2017	January 1, 2017 through April 28, 2017
Revenues:			
Crude oil sales(1)	$112,479	$21,016	$51,593
Natural gas sales(2)	10,563	3,606	8,584
Natural gas liquids sales	12,191	3,237	7,867
Product revenue	$135,233	$27,859	$68,044
Sales Volumes:			
Crude oil (MBbls)	1,847.8	484.3	1,068.5
Natural gas (MMcf)	4,313.0	1,557.2	3,336.1
Natural gas liquids (MBbls)	582.2	209.5	449.0
Crude oil equivalent (MBoe)(3)	3,148.8	953.4	2,073.5
Average Sales Prices (before derivatives)(4):			
Crude oil (per Bbl)	$60.87	$43.39	$48.29
Natural gas (per Mcf)	$2.45	$2.32	$2.57
Natural gas liquids (per Bbl)	$20.94	$15.45	$17.52
Crude oil equivalent (per Boe)(3)	$42.95	$29.22	$32.82
Average Sales Prices (after derivatives)(4):			
Crude oil (per Bbl)	$54.47	$43.39	$48.29
Natural gas (per Mcf)	$2.50	$2.32	$2.57
Natural gas liquids (per Bbl)	$20.94	$15.45	$17.52
Crude oil equivalent (per Boe)(3)	$39.26	$29.22	$32.82

(1) Crude oil sales excludes $0.2 million, $0.1 million, and $0.1 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the Current Successor Period, Prior Successor Period and Prior Predecessor Period, respectively.

(2) Natural gas sales excludes $0.6 million, $0.2 million, and $0.4 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the Current Successor Period, Prior Successor Period and Prior Predecessor Period, respectively.

(3) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.

(4) The derivatives economically hedge the price we receive for crude oil. For the Current Successor Period, the derivative cash settlement loss for oil contracts was $11.8 million and the derivative cash settlement gain for natural gas contracts was $0.2 million. Please refer to Note 11 - Derivatives of Part I, Item 1 of this report for additional disclosures.

Revenues increased for the Current Successor Period by 41%, to $135.2 million, compared to $95.9 million for the combined Prior Successor and Predecessor Period, due to a combination of a 36% increase in oil equivalent pricing and a 4.0% increase in sales volumes. In addition to the overall increase due to operations, there was an increase of $4.0 million related to the adoption of ASC 606, which caused certain revenues to be shown gross compared to a historical net presentation. Please refer to Note 3 - Revenue Recognition of Part I, Item 1 of this report for additional information.

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The following table summarizes our operating expenses for the periods indicated:

	Successor		Predecessor
	Six Months Ended June 30, 2018	April 29, 2017 through June 30, 2017	January 1, 2017 through April 28, 2017
Expenses:			
Lease operating expense	$21,775	$6,153	$13,128
Gas plant and midstream operating expense	6,860	1,762	3,541
Gathering, transportation and processing	3,998	—	—
Severance and ad valorem taxes	11,303	2,408	5,671
Exploration	250	359	3,699
Depreciation, depletion and amortization	17,072	4,836	28,065
Abandonment and impairment of unproved properties	4,979	—	—
Unused commitments	21	—	993
General and administrative	19,451	16,139	15,092
Operating Expenses	$85,709	$31,657	$70,189
Selected Costs ($ per Boe):			
Lease operating expense	$6.92	$6.45	$6.33
Gas plant and midstream operating expense	2.18	1.85	1.71
Gathering, transportation and processing	1.27	—	—
Severance and ad valorem taxes	3.59	2.53	2.73
Exploration	0.08	0.38	1.78
Depreciation, depletion and amortization	5.42	5.07	13.54
Abandonment and impairment of unproved properties	1.58	—	—
Unused commitments	0.01	—	0.48
General and administrative	6.18	16.93	7.28
Operating Expenses	$27.23	$33.21	$33.85

Lease operating expense. Our lease operating expense increased $2.5 million, or 13%, to $21.8 million for the Current Successor Period from $19.3 million for the combined Prior Successor and Predecessor Period, and increased on an equivalent basis to $6.92 per Boe from $6.37 per Boe. The Company experienced a $0.8 million increase in pumping and gauging charges, $0.5 million increase in compression charges, and $1.2 million increase in well servicing charges during the Current Successor Period when compared to the same period in 2017. The increase in costs is largely associated with the accelerated schedule of compressor exchanges within our Rocky Mountain region.

Gas plant and midstream operating expense. Our gas plant and midstream operating expense increased $1.6 million, or 29%, to $6.9 million for the Current Successor Period from $5.3 million for the Prior Successor and Predecessor Period. Gas plant and midstream operating expense per Boe increased 25% during the comparable periods due to the costs associated with the accelerated schedule of compressor exchanges within our Rocky Mountain Infrastructure gathering systems.

Gathering, transportation and processing. As noted in the operating revenues section above, the increase to gathering, transportation and processing expense during the Current Successor Period to $4.0 million is related to the Company's adoption of ASC 606 during the Current Successor Period, which caused certain revenues to be shown gross, with the related expenses recorded in this line item. Please refer to Note 3 - Revenue Recognition of Part I, Item 1 of this report for additional information.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased 40% to $11.3 million for the Current Successor Period from $8.1 million for the combined Prior Successor and Predecessor Period. Severance and ad valorem taxes primarily correlate to revenue, which increased 41% over the comparable period.

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Exploration. Our exploration expense of $0.3 million during the Current Successor Period was due to delay rental payments. Exploration expense of $4.1 million during the combined Prior Successor and Predecessor Period was due to $0.7 million of seismic charges for data within our Wattenberg Field, a write-off of $3.0 million for abandoned location costs within our Dorcheat Macedonia and Wattenberg Fields, and $0.4 million in delay lease rental payments.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense per Boe was $5.42, $5.07, and $13.54 for the Current Successor Period, the Prior Successor Period, and Prior Predecessor Period, respectively. The Prior Successor Periods reflect the $310.6 million fair value downward adjustment to the depletable asset base upon adoption of fresh-start accounting. The Current Successor Period excludes depreciation, depletion and amortization on the assets held for sale. The increase in depreciation, depletion and amortization during the Current Successor Period when compared to the Prior Successor Period primarily correlates to an increase in capital expenditures.

Abandonment and impairment of unproved properties. The Company incurred $5.0 million of impairment charges relating to non-core leases expiring and the standard amortization of unproved properties within the Wattenberg Field during the Current Successor Period. There were no abandonment and impairment of unproved properties during the Prior Successor and Predecessor Periods.

Unused commitments. We incurred minimal unused commitment fees during the Current Successor Period. There were no unused commitments during the Prior Successor Period. During the Prior Predecessor Period, we incurred $1.0 million in unused commitment fees on a water supply contract in the Wattenberg Field.

General and administrative. Our general and administrative expense decreased by $11.7 million to $19.5 million for the Current Successor Period from $31.2 million for the combined Prior Successor and Predecessor Period. On a per Boe basis our general and administrative expense was $6.18 for the Current Successor Period and $10.32 on the combined Prior Successor and Predecessor Period. The Prior Successor Period reflects a one-time $7.1 million non-cash stock-based compensation charge from the vesting of the Company's former Chief Executive Officer's stock awards upon separation from the Company, and when adjusted for the one-time charge, the combined Prior Successor and Predecessor Period was $7.96 on a per Boe basis. The incremental decrease in general and administrative expense during the Current Successor Period, when compared to the combined Prior Successor and Predecessor Periods, is due to a $2.7 million decrease in salaries and benefits due to workforce reductions, $0.7 million decrease in advisor fees, and $0.6 million decrease in office rent due to negotiations during bankruptcy.

Derivative loss. Our derivative loss for the Current Successor Period was $30.8 million. We had no derivative contracts during the Prior Successor or Predecessor Periods. Our derivative loss is due to settlements and fair market value adjustments caused by market prices being higher than our contracted hedge prices. Please refer to Note 11 - Derivatives above for additional discussion.

Interest expense. Our interest expense for the Current Successor Period, the Prior Successor Period, and the Prior Predecessor Period was $1.2 million, $0.2 million, and $5.7 million, respectively. Upon filing its petition for Chapter 11, the Company ceased accruing interest expense on its Senior Notes. The Company incurred $0.8 million in interest expense associated with the credit facility and $0.4 million in commitment fees on the available borrowing base under the credit facility during the Current Successor Period. The Company incurred $0.2 million in commitment fees on the available borrowing base under the credit facility during the Prior Successor Period. Interest expense on the Senior Notes was $1.0 million for the Prior Predecessor Period, with the remaining interest expense relating to the predecessor credit facility. Average debt outstanding for the Current Successor Period and the Prior Predecessor Period was $28.1 million and $657.5 million, respectively. The Company had no outstanding debt during the Prior Successor Period.

Reorganization items, net. Our reorganization income was $8.8 million for the Prior Predecessor Period. Upon filing its petition for Chapter 11, the Company incurred a $51.2 million make-whole payment on the Senior Notes, incurred

$31.7 million in legal and professional fees, and wrote-off $6.2 million of debt issuance and premium costs on the Senior Notes. Upon adoption of fresh-start accounting, the Company incurred a $412.9 million gain on settlement of liabilities subject to compromise, a $311.4 million loss on fresh-start valuation adjustments, and $3.7 million for professional fees and other charges.

Liquidity and Capital Resources

The Company's anticipated sources of liquidity include cash from operating activities, borrowings under the credit facility, proceeds from sales of assets, and potential proceeds from capital and debt market transactions. Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for our crude oil, NGLs, and natural

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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. To mitigate some of the pricing risk, we have 49% of our 2018 guided production hedged as of June 30, 2018 and as of the filing date of this report.

As of June 30, 2018, our liquidity was $153.7 million, consisting of cash on hand of $22.0 million and $131.7 million of available borrowing capacity on the credit facility. Please refer to Note 6 - Long-term Debt in Part I, Item 1 above for additional discussion.

We anticipate investing approximately $275.0 million to $295.0 million, which will support drilling 77 gross wells and turning online 49 gross wells in 2018.

Our weighted-average interest rates on borrowings from the credit facility was 5.12% for the Current Successor Period.

The following table summarizes our cash flows and other financial measures for the periods indicated (in thousands):

	Successor		Predecessor
	Six Months Ended June 30, 2018	April 29, 2017 through June 30, 2017	January 1, 2017 through April 28, 2017
Net cash provided by (used in) operating activities	$42,149	$(3,833)	$(19,884)
Net cash used in investing activities	(93,037)	(10,056)	(6,022)
Net cash provided by (used in) financing activities	60,174	(2,080)	15,406
Cash, cash equivalents and restricted cash	22,068	52,437	68,406
Acquisition of oil and gas properties	1,295	4,982	445
Exploration and development of oil and gas properties	91,482	4,913	5,123

Cash flows provided by (used in) operating activities

The Current Successor Period and the Prior Successor Period included cash receipts and disbursements attributable to our normal operating cycle. The Prior Predecessor Period contained reorganization costs along with our normal operating receipts and disbursements. See Results of Operations above for more information on the factors driving these changes.

Cash flows used in investing activities

Expenditures for development of oil and natural gas properties are the primary use of our capital resources. The Company spent $92.8 million, $9.9 million, and $5.6 million on the exploration, development, and acquisition of oil and gas properties during the Current Successor Period, Prior Successor Period, and Prior Predecessor Period, respectively. The increase in capital expenditures among the periods is a direct result of emerging from bankruptcy and resuming development operations.

Cash flows provided by (used in) financing activities

Net cash provided by financing activities for the Current Successor Period is due to drawing $60.0 million on our credit facility. Net cash used in financing activities for the Prior Successor Period consisted of $2.1 million for employee tax withholdings in exchange for the return of common stock. Net cash provided by financing activities for the Prior Predecessor Period consisted of proceeds from the rights offering of $207.5 million net of the $191.7 million repayment to the predecessor revolving credit facility.

New Accounting Pronouncements

Please refer to Note 2 — Basis of Presentation under Part I, Item 1 of this report for any recently issued or adopted accounting standards.

Critical Accounting Policies and Estimates

Information regarding our critical accounting policies and estimates is contained in Part II, Item 7 of our 2017 Form 10-K.

Effects of Inflation and Pricing

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Although the impact of inflation has been relatively insignificant in recent years, it is still a factor in the United States economy, and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations, depletion expense, impairment assessments of oil and gas properties, asset retirement obligation, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money, and retain personnel.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Contractual Obligations

There have been no significant changes from our 2017 Form 10-K in our obligations and commitments. Please refer to Note 7 - Commitments and Contingencies under Part I, Item 1 of this report for additional discussion.

Cautionary Note Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q contains various statements, including those that express belief, expectation or intention, as well as those that are not statements of historic fact, that are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended (the “Exchange Act”). When used in this Quarterly Report on Form 10-Q, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project,” “plan,” “will,” and expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward looking statements include statements related to, among other things:

- the Company's business strategies and intent to maximize liquidity;
- reserves estimates;
- estimated sales volumes;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- ability to modify future capital expenditures;
- the Wattenberg Field being a premier oil and resource play in the United States;
- anticipated costs;
- compliance with debt covenants;
- ability to fund and satisfy obligations related to ongoing operations;
- compliance with government regulations, including environmental, health, and safety regulations and liabilities thereunder;
- adequacy of gathering systems and continuous improvement of such gathering systems;
- impact from the lack of available gathering systems and processing facilities in certain areas;
- natural gas, oil, and natural gas liquid prices and factors affecting the volatility of such prices;
- impact of lower commodity prices;
- sufficiency of impairments;
- the ability to use derivative instruments to manage commodity price risk and ability to use such instruments in the future;

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- our drilling inventory and drilling intentions;
- impact of potentially disruptive technologies;
- our estimated revenues and losses;
- the timing and success of specific projects;
- our implementation of standard and long reach laterals in the Wattenberg Field;
- our use of multi-well pads to develop the Niobrara and Codell formations;
- intention to continue to optimize enhanced completion techniques and well design changes;
- stated working interest percentages;
- management and technical team;
- outcomes and effects of litigation, claims, and disputes;
- primary sources of future production growth;
- full delineation of the Niobrara B and C benches in our legacy acreage;
- our ability to replace oil and natural gas reserves;
- our ability to convert PUDs to producing properties within five years of their initial proved booking;
- impact of recently issued accounting pronouncements;
- impact of the loss a single customer or any purchaser of our products;
- timing and ability to meet certain volume commitments related to purchase and transportation agreements;
- the impact of customary royalty interests, overriding royalty interests, obligations incident to operating agreements, liens for current taxes, and other industry-related constraints;
- our financial position;
- our cash flow and liquidity;
- the adequacy of our insurance; and
- other statements concerning our operations, economic performance, and financial condition.

We have based these forward-looking statements on certain assumptions and analyses we have made in light of our experience and our perception of historical trends, current conditions, and expected future developments as well as other factors we believe are appropriate under the circumstances. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. The actual results or developments anticipated by these forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, and may not be realized or, even if substantially realized, may not have the expected consequences. Actual results could differ materially from those expressed or implied in the forward-looking statements.

Factors that could cause actual results to differ materially include, but are not limited to, the following:

- the risk factors discussed in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2017;
- further declines or volatility in the prices we receive for our oil, natural gas liquids, and natural gas;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- ability of our customers to meet their obligations to us;
- our access to capital;

- our ability to generate sufficient cash flow from operations, borrowings, or other sources to enable us to fully develop our undeveloped acreage positions;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future sales volume rates and associated costs;
- uncertainties associated with estimates of proved oil and gas reserves;
- the possibility that the industry may be subject to future local, state, and federal regulatory or legislative actions (including additional taxes and changes in environmental regulation);
- environmental risks;
- seasonal weather conditions;
- lease stipulations;
- drilling and operating risks, including the risks associated with the employment of horizontal drilling techniques;
- our ability to acquire adequate supplies of water for drilling and completion operations;
- availability of oilfield equipment, services, and personnel;
- exploration and development risks;
- competition in the oil and natural gas industry;
- management’s ability to execute our plans to meet our goals;
- our ability to attract and retain key members of our senior management and key technical employees;
- our ability to maintain effective internal controls;
- access to adequate gathering systems and pipeline take-away capacity;
- our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;
- costs and other risks associated with perfecting title for mineral rights in some of our properties;
- continued hostilities in the Middle East and other sustained military campaigns or acts of terrorism or sabotage; and
- other economic, competitive, governmental, legislative, regulatory, geopolitical, and technological factors that may negatively impact our businesses, operations, or pricing.

All forward-looking statements speak only as of the date of this report. We disclaim any obligation to update or revise these statements unless required by law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions, and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions, or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Part II, Item 1A. Risk Factors and Part I, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this report. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Oil and Natural Gas Price Risk

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil and natural gas, the global supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels, local and global politics, and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations, and capital resources.

Commodity Derivative Contracts

Our primary commodity risk management objective is to reduce volatility in our cash flows. We enter into derivative contracts for oil and natural gas using NYMEX futures or over-the-counter derivative financial instruments with only counterparties whom we believe are well-capitalized and have been approved by our Board of Directors.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments, or (2) our counterparties fail to purchase the contracted quantities of oil or otherwise fail to perform. To the extent that we engage in derivative contracts, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in such prices.

As of June 30, 2018, and through the filing date of this report, all of our derivative arrangements are concentrated with four counterparties, all of which are lenders under our credit facility. If these counterparties fail to perform their obligations, we may suffer financial loss or be prevented from realizing the benefits of favorable price changes in the physical market.

The result of oil market prices exceeding our swap prices requires us to make payment for the settlement of our derivatives, if owed by us, generally up to 15 business days before we receive market price cash payments from our customers. This could have a material adverse effect on our cash flows for the period between derivative settlement and payment for revenues earned.

Interest Rates

As of June 30, 2018, we had $60.0 million outstanding under our credit facility. Borrowings under our credit facility bear interest at a fluctuating rate that is tied to an adjusted Base Rate or London Interbank Offered Rate, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flow. As of June 30, 2018, and through the filing date of this report, the Company was in compliance with all financial and non-financial covenants.

Counterparty and Customer Credit Risk

In connection with our derivatives activity, we have exposure to financial institutions in the form of derivative transactions. Four lenders under our successor credit facility are currently counterparties on our derivative instruments currently in place and have investment grade credit ratings.

We are also subject to credit risk due to concentration of our oil and natural gas receivables with certain significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history and financial resources of our customers, but we do not require our customers to post collateral.

Marketability of Our Production

The marketability of our production from the Mid-Continent and Rocky Mountain regions depends in part upon the availability, proximity and capacity of third-party refineries, access to regional trucking, pipeline and rail infrastructure, natural gas gathering systems, and processing facilities. We deliver crude oil and natural gas produced from these areas through trucking services, and pipelines that we do not own. The lack of availability or capacity on these systems and facilities could

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reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, adverse weather, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Currently, there are no pipeline systems that service wells in French Lake. If neither we nor a third-party constructs the required pipeline system, we may not be able to fully test or develop our resources in French Lake.

There have not been material changes to the interest rate risk analysis or oil and gas price sensitivity analysis disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of June 30, 2018. The term “disclosure controls and procedures,” as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in SEC rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company’s management, including its principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of June 30, 2018, our principal executive officer and principal financial officer concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives, and management necessarily applies its judgment in evaluating the cost-benefit relationship of possible controls and procedures. To assist management, we have established an internal audit function to verify and monitor our internal controls and procedures. The Company’s internal control system is supported by written policies and procedures, contains self-monitoring mechanisms and is audited by the internal audit function. Appropriate actions are taken by management to correct deficiencies as they are identified.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in management’s evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the quarter ended June 30, 2018 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. Like other oil and gas producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental, health, and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. As of the date of this filing, there are no material pending or overtly threatened legal actions against us of which we are aware.

As previously described in our 2017 Form 10-K, the Company and the CDPHE agreed to a COC resolving the matters addressed by a compliance advisory issued to the Company for certain storage tank facilities located in the Wattenberg Field with respect to applicable air quality regulations. Pursuant to the terms of the COC, the Company paid an administrative penalty of $0.2 million in 2017. The Company must also adopt procedures and processes to address the monitoring, reporting, and control of air emissions. The COC further sets forth compliance requirements and criteria for continued operations and contains provisions regarding record-keeping, modifications to the COC, circumstances under which the COC may terminate with respect to certain wells and facilities, and the sale or transfer of operational or ownership interests covered by the COC. In order to be in compliance, the Company incurred $0.7 million in 2017, and currently anticipates spending $3.5 million in 2018,

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and $3.1 million for 2019 through 2022. The COC can be terminated after four years with a showing of substantial compliance and CDPHE approval.

There have been no other material changes to our legal proceedings from those described in our Annual Report on Form 10-K for the year ended December 31, 2017.

Item 1A. Risk Factors.

Our business faces many risks. Any of the risk factors discussed in this report or our other SEC filings could have a material im