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

Form 10-Q

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

For the quarterly period ended March 31, 2018

OR

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

For the transition period from ______ to ______

Commission file number: 333-134748

Chaparral Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**73-1590941** **(I.R.S. Employer Identification No.)**
701 Cedar Lake Boulevard **Oklahoma City, Oklahoma** **(Address of principal executive offices)**	**73114** **(Zip code)**

(405) 478-8770
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer (Do not check if a smaller reporting company)			☒
Smaller reporting company			☐
Emerging growth company			☐

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

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☒ No ☐

Number of shares outstanding of each of the issuer's classes of common stock as of May 9, 2018:

Class	Number of Shares
Class A Common Stock, $0.01 par value	38,626,615
Class B Common Stock, $0.01 par value	7,871,512

CHAPARRAL ENERGY, INC.
Index to Form 10-Q

CAUTIONARY NOTE

REGARDING FORWARD-LOOKING STATEMENTS

This report includes statements that constitute forward-looking statements within the meaning of the federal securities laws. These statements are subject to risks and uncertainties. These statements may relate to, but are not limited to, information or assumptions about us, our capital and other expenditures, dividends, financing plans, capital structure, cash flow, pending legal and regulatory proceedings and claims, including environmental matters, future economic performance, operating income, cost savings, and management's plans, strategies, goals and objectives for future operations and growth. These forward-looking statements generally are accompanied by words such as "intend," "anticipate," "believe," "estimate," "expect," "should," "seek," "project," "plan" or similar expressions. Any statement that is not a historical fact is a forward-looking statement. It should be understood that these forward-looking statements are necessarily estimates reflecting the best judgment of senior management, not guarantees of future performance. They are subject to a number of assumptions, risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the forward-looking statements. Forward-looking statements in this report may include, for example, statements about:

- fluctuations in demand or the prices received for oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling, completion and performance of wells;
- competition and government regulations;
- timing and amount of future production of oil and natural gas;
- costs of exploiting and developing properties and conducting other operations, in the aggregate and on a per-unit equivalent basis;
- changes in proved reserves;
- operating costs and other expenses;
- our future financial condition, results of operations, revenue, cash flows and expenses;
- estimates of proved reserves;
- exploitation of property acquisitions; and
- marketing of oil and natural gas.

These forward-looking statements represent intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors. Many of those factors are outside of our control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. In addition to the risk factors described in Part II, Item 1A. Risk Factors, of this report and Part I, Item 1A. Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2017, the factors include:

- the ability to operate our business following emergence from bankruptcy;
- worldwide supply of and demand for oil and natural gas;
- volatility and declines in oil and natural gas prices;
- drilling plans (including scheduled and budgeted wells);
- our new capital structure and the adoption of fresh start accounting, including the risk that assumptions and factors used in estimating enterprise value vary significantly from current values;
- the number, timing or results of any wells;
- changes in wells operated and in reserve estimates;
- future growth and expansion;
- future exploration;
- integration of existing and new technologies into operations;
- future capital expenditures (or funding thereof) and working capital;
- availability and cost of equipment

- risks related to the concentration of our operations in the mid-continent geographic area;
- borrowings and capital resources and liquidity;
- changes in strategy and business discipline, including our post-emergence business strategy;
- future tax matters;
- legislation and regulatory initiatives
- any loss of key personnel;
- geopolitical events affecting oil and natural gas prices;
- outcome, effects or timing of legal proceedings;
- the effect of litigation and contingencies;
- environmental litigation
- the ability to generate additional prospects; and
- the ability to successfully complete merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions may change the schedule of any future production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of these risks or uncertainties materialize, or should any of our assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements contained herein. We undertake no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required under applicable securities laws. All forward-looking statements included herein are expressly qualified in their entirety by the cautionary statements contained or referred to in this section.

GLOSSARY OF CERTAIN DEFINED TERMS

The terms defined in this section are used throughout this Form 10-Q:

Basin	A low region or natural depression in the earth's crust where sedimentary deposits accumulate.
Bbl	One stock tank barrel of 42 U.S. gallons liquid volume used herein in reference to crude oil, condensate, or natural gas liquids.
BBtu	One billion British thermal units.
Boe	Barrels of oil equivalent using the ratio of six thousand cubic feet of natural gas to one barrel of oil.
Boe/d	Barrels of oil equivalent per day.
Btu	British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.
Completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.
CO_2	Carbon dioxide.
Dry well or dry hole	An exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.
Enhanced oil recovery (EOR)	The use of any improved recovery method, including injection of CO_2 or polymer, to remove additional oil after Secondary Recovery.
EOR Areas	Areas where we previously injected and/or recycle CO_2 as a means of oil recovery which were divested in November 2017.
Exit Credit Facility	Ninth Restated Credit Agreement, dated as of March 21, 2017, by and among us, Chaparral Energy, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent and The Lenders and Prepetition Borrowers Party thereto.
Exit Revolver	A first-out revolving facility under the Exit Credit Facility.
Exit Term Loan	A second-out term loan under the Exit Credit Facility.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
MBbls	One thousand barrels of crude oil, condensate, or natural gas liquids.
MBoe	One thousand barrels of crude oil equivalent.
Mcf	One thousand cubic feet of natural gas.
MMBtu	One million British thermal units.
MMcf	One million cubic feet of natural gas.
MMcf/d	Millions of cubic feet per day.
Natural gas liquids (NGLs)	Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing or cycling plants. Natural gas liquids primarily include propane, butane, isobutane, pentane, hexane and natural gasoline.

New Credit Facility	Tenth Restated Credit Agreement, dated as of December 21, 2017, by and among us, Chaparral Energy, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent and The Lenders and Prepetition Borrowers Party thereto.
NYMEX	The New York Mercantile Exchange.
Play	A term describing an area of land following the identification by geologists and geophysicists of reservoirs with potential oil and natural gas reserves.
Prior Credit Facility	Eighth Restated Credit Agreement, dated as of April 12, 2010, by and among us, Chaparral Energy, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent and The Lenders and Prepetition Borrowers Party thereto.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared to the cost of a new well.
Proved reserves	The quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.
Proved undeveloped reserves	Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
PV-10 value	When used with respect to oil and natural gas reserves, PV-10 value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, excluding escalations of prices and costs based upon future conditions, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10%.
Reorganization Plan	First Amended Joint Plan of Reorganization for Chaparral Energy, Inc. and its Affiliate Debtors under Chapter 11 of the Bankruptcy Code.
SEC	The Securities and Exchange Commission.
Secondary Recovery	The recovery of oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Secondary Recovery methods are often applied when production slows due to depletion of the natural pressure.
Senior Notes	Collectively, our 9.875% senior notes due 2020, 8.25% senior notes due 2021, and 7.625% senior notes due 2022, of which all obligations have been discharged upon consummation of our Reorganization Plan.
STACK	An acronym standing for Sooner Trend Anadarko Canadian Kingfisher. A play in the Anadarko Basin of Oklahoma in which we operate.
Unit	The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

PART I — FINANCIAL INFORMATION

ITEM 1. ***FINANCIAL STATEMENTS***

Chaparral Energy, Inc. and subsidiaries
Consolidated balance sheets
(Unaudited)

(dollars in thousands, except share data)	March 31, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 12,189	$ 27,732
Accounts receivable, net	70,495	60,363
Inventories, net	7,463	5,138
Prepaid expenses	2,898	2,661
Total current assets	93,045	95,894
Property and equipment, net	49,004	50,641
Oil and natural gas properties, using the full cost method:		
Proved	668,184	634,294
Unevaluated (excluded from the amortization base)	550,082	482,239
Accumulated depreciation, depletion, amortization and impairment	(142,107)	(124,180)
Total oil and natural gas properties	1,076,159	992,353
Other assets	361	418
Total assets	$ 1,218,569	$ 1,139,306
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 72,317	$ 75,414
Accrued payroll and benefits payable	7,131	11,276
Accrued interest payable	576	187
Revenue distribution payable	20,118	17,966
Long-term debt and capital leases, classified as current	3,306	3,273
Derivative instruments	10,548	8,959
Total current liabilities	113,996	117,075
Long-term debt and capital leases, less current maturities	219,842	141,386
Derivative instruments	14,835	4,167
Deferred compensation	813	696
Asset retirement obligations	33,601	33,216
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Preferred stock, 5,000,000 shares authorized, none issued and outstanding	—	—
Class A Common stock, $0.01 par value, 180,000,000 shares authorized and 38,872,480 issued and 38,808,561 outstanding at March 31, 2018 and 38,956,250 shares issued and outstanding at December 31, 2017	388	389
Class B Common stock, $0.01 par value, 20,000,000 shares authorized and 7,871,512 shares issued and outstanding at March 31, 2018 and December 31, 2017	79	79
Additional paid in capital	966,781	961,200
Treasury stock, at cost, 63,919 shares as of March 31, 2018	(1,422)	—
Accumulated deficit	(130,344)	(118,902)
Total stockholders' equity	835,482	842,766
Total liabilities and stockholders' equity	$ 1,218,569	$ 1,139,306

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

Chaparral Energy, Inc. and subsidiaries
Consolidated statements of operations
(Unaudited)

(in thousands, except share and per share data)	Successor: Three months ended March 31, 2018	Successor: Period from March 22, 2017 through March 31, 2017	Predecessor: Period from January 1, 2017 through March 21, 2017
Revenues:			
Net commodity sales	57,889	7,808	66,531
Sublease revenue	1,198	—	—
Total revenues	59,087	7,808	66,531
Costs and expenses:			
Lease operating	14,543	4,259	19,941
Transportation and processing	—	361	2,034
Production taxes	2,677	316	2,417
Depreciation, depletion and amortization	21,106	3,414	24,915
General and administrative	11,507	5,744	6,843
Cost reduction initiatives	—	6	629
Other	828	—	—
Total costs and expenses	50,661	14,100	56,779
Operating income (loss)	8,426	(6,292)	9,752
Non-operating (expense) income:			
Interest expense	(1,371)	(650)	(5,862)
Derivative (losses) gains	(16,501)	(12,115)	48,006
(Loss) gain on sale of assets	(1,044)	—	206
Other income (expense), net	85	(5)	1,167
Net non-operating (expense) income	(18,831)	(12,770)	43,517
Reorganization items, net	(1,037)	(620)	988,727
(Loss) income before income taxes	(11,442)	(19,682)	1,041,996
Income tax expense	—	1	37
Net (loss) income	$ (11,442)	$ (19,683)	$ 1,041,959
Earnings per share:			
Basic for Class A and Class B	$ (0.25)	*	*
Diluted for Class A and Class B	$ (0.25)	*	*
Weighted average shares used to compute earnings per share:			
Basic for Class A and Class B	45,143,297	*	*
Diluted for Class A and Class B	45,143,297	*	*

* Item not disclosed. See “Note 2—Earnings per share.”

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

Chaparral Energy, Inc. and subsidiaries
Consolidated statements of stockholders' equity
(Unaudited)

(dollars in thousands)	Common stock Shares outstanding	Common stock Amount	Additional paid in capital	Treasury stock	Accumulated deficit	Total
Balance at December 31, 2017	46,827,762	$ 468	$ 961,200	$ —	$ (118,902)	$ 842,766
Stock-based compensation	—	—	5,581	—	—	5,581
Restricted stock forfeited	(83,770)	(1)	—	—	—	(1)
Repurchase of common stock	(63,919)	—	—	(1,422)	—	(1,422)
Net loss	—	—	—	—	(11,442)	(11,442)
Balance at March 31, 2018	46,680,073	$ 467	$ 966,781	$ (1,422)	$ (130,344)	$ 835,482

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

Chaparral Energy, Inc. and subsidiaries
Consolidated statements of cash flows
(Unaudited)

(in thousands)	Successor: Three months ended March 31, 2018	Successor: Period from March 22, 2017 through March 31, 2017	Predecessor: Period from January 1, 2017 through March 21, 2017
Cash flows from operating activities			
Net (loss) income	$ (11,442)	$ (19,683)	$ 1,041,959
Adjustments to reconcile net (loss) income to net cash provided by operating activities			
Non-cash reorganization items	—	—	(1,012,090)
Depreciation, depletion and amortization	21,106	3,414	24,915
Derivative losses (gains)	16,501	12,115	(48,006)
Loss (gain) on sale of assets	1,044	—	(206)
Other	1,630	1,012	645
Change in assets and liabilities			
Accounts receivable	(12,140)	(3,577)	198
Inventories	(3,168)	38	466
Prepaid expenses and other assets	(179)	180	(497)
Accounts payable and accrued liabilities	(9,828)	(3,423)	8,733
Revenue distribution payable	2,151	1,510	(1,875)
Deferred compensation	4,701	13	143
Net cash provided by (used in) operating activities	10,376	(8,401)	14,385
Cash flows from investing activities			
Expenditures for property, plant, and equipment and oil and natural gas properties	(99,941)	(5,832)	(31,179)
Proceeds from asset dispositions	73	—	1,884
(Payments) proceeds from derivative instruments	(4,244)	1,692	1,285
Net cash used in investing activities	(104,112)	(4,140)	(28,010)
Cash flows from financing activities			
Proceeds from long-term debt	79,000	—	270,000
Repayment of long-term debt	(146)	(19)	(444,785)
Proceeds from rights offering, net	—	—	50,031
Principal payments under capital lease obligations	(661)	(69)	(568)
Payment of other financing fees	—	—	(2,410)
Net cash provided by (used in) financing activities	78,193	(88)	(127,732)
Net decrease in cash, cash equivalents, and restricted cash	(15,543)	(12,629)	(141,357)
Cash, cash equivalents, and restricted cash at beginning of period	27,732	45,123	186,480
Cash, cash equivalents, and restricted cash at end of period	$ 12,189	$ 32,494	$ 45,123

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

Note 1: Nature of operations and summary of significant accounting policies

Nature of operations

Chaparral Energy, Inc. and its subsidiaries (collectively, "we", "our", "us", or the "Company") are involved in the acquisition, exploration, development, production and operation of oil and natural gas properties. Our properties are located primarily in Oklahoma and our commodity products include crude oil, natural gas and natural gas liquids.

Reorganization, fresh start accounting and comparability of financial statements to prior periods

On May 9, 2016, the Company and ten of its subsidiaries filed voluntary petitions seeking relief under Title 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court") commencing cases for relief under Chapter 11 of the Bankruptcy Code.

On March 10, 2017, the Bankruptcy Court confirmed our Reorganization Plan and on March 21, 2017 (the "Effective Date"), the Reorganization Plan became effective and we emerged from bankruptcy. Upon emergence, all existing equity was cancelled and we issued new common stock to the previous holders of our Senior Notes and certain general unsecured creditors whose claims were impaired as a result of our bankruptcy, as well as to certain other parties as set forth in the Reorganization Plan, including to parties participating in a rights offering.

Additionally, upon emergence we qualified for and applied fresh start accounting to our financial statements in accordance with the provisions set forth in FASB Accounting Standards Codification (ASC) 852: Reorganizations, as (i) the holders of existing voting shares of the Company prior to its emergence received less than 50% of the voting shares of the Company outstanding following its emergence from bankruptcy and (ii) the reorganization value of our assets immediately prior to confirmation of the Reorganization Plan was less than the post-petition liabilities and allowed claims.

As a result of the application of fresh start accounting, as well as the effects of the implementation of the Reorganization Plan, the Company's consolidated financial statements after March 21, 2017, are not comparable with the consolidated financial statements prior to that date. To facilitate our financial statement presentations, we refer to the post-emergence reorganized company in these consolidated financial statements and footnotes as the "Successor" for periods subsequent to March 21, 2017, and to the pre-emergence company as "Predecessor" for periods prior to and including March 21, 2017.

Interim financial statements

The accompanying unaudited consolidated interim financial statements of the Company have been prepared in accordance with the rules and regulations of the SEC and do not include all of the financial information and disclosures required by accounting principles generally accepted in the United States of America ("GAAP") for complete financial statements. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2017.

The financial information as of March 31, 2018 (Successor), and for the three months ended March 31, 2018 (Successor), and the periods of March 22, 2017, through March 31, 2017 (Successor), and January 1, 2017, through March 21, 2017 (Predecessor), is unaudited. 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. In management's opinion, such information contains all adjustments considered necessary for a fair presentation of the results of the interim periods. The results of operations for the three months ended March 31, 2018 (Successor) are not necessarily indicative of the results of operations that will be realized for the year ended December 31, 2018.

Certain reclassifications have been made to prior period financial statements to conform to current period presentation. The reclassifications had no effect on our previously reported results of operations.

Cash and cash equivalents

We maintain cash and cash equivalents in bank deposit accounts and money market funds which may not be federally insured. As of March 31, 2018, cash with a recorded balance totaling approximately $10,330 was held at JP Morgan Chase Bank, N.A. We have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk on such accounts.

(dollars in thousands, except per share amounts)

Accounts receivable

We have receivables from joint interest owners and oil and natural gas purchasers which are generally uncollateralized. Accounts receivable consisted of the following:

	March 31, 2018	December 31, 2017
Joint interests	$ 37,339	$ 29,032
Accrued commodity sales	30,761	26,516
Derivative settlements	10	157
Other	3,008	5,326
Allowance for doubtful accounts	(623)	(668)
	$ 70,495	$ 60,363

Inventories

Inventories consisted of the following:

	March 31, 2018	December 31, 2017
Equipment inventory	$ 6,440	$ 4,163
Commodities	1,202	1,154
Inventory valuation allowance	(179)	(179)
	$ 7,463	$ 5,138

Oil and natural gas properties

Costs associated with unevaluated oil and natural gas properties are excluded from the amortizable base until a determination has been made as to the existence of proved reserves. Unevaluated leasehold costs are transferred to the amortization base with the costs of drilling the related well upon proving up reserves of a successful well or upon determination of a dry or uneconomic well under a process that is conducted each quarter. Furthermore, unevaluated oil and natural gas properties are reviewed for impairment if events and circumstances exist that indicate a possible decline in the recoverability of the carrying amount of such property. The impairment assessment is conducted at least once annually and whenever there are indicators that impairment has occurred. In assessing whether impairment has occurred, we consider factors such as intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and economic viability of development if proved reserves are assigned. Upon determination of impairment, all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization. The processes above are applied to unevaluated oil and natural gas properties on an individual basis or as a group if properties are individually insignificant. Our future depreciation, depletion and amortization rate would increase if costs are transferred to the amortization base without any associated reserves.

In the past, the costs associated with unevaluated properties typically related to acquisition costs of unproved acreage. As a result of the application of fresh start accounting in the first quarter of 2017, a substantial portion of the carrying value of our unevaluated properties are the result of a fair value increase to reflect the value of our acreage in our STACK play.

The costs of unevaluated oil and natural gas properties consisted of the following:

	March 31, 2018	December 31, 2017
Leasehold acreage	$ 527,450	$ 466,711
Capitalized interest	3,655	2,134
Wells and facilities in progress of completion	18,977	13,394
Total unevaluated oil and natural gas properties excluded from amortization	$ 550,082	$ 482,239

Ceiling Test. In accordance with the full cost method of accounting, the net capitalized costs of oil and natural gas properties are not to exceed their related PV-10 value, net of tax considerations, plus the cost of unproved properties not being amortized.

Our estimates of oil and natural gas reserves as of March 31, 2018, and the related PV-10 value, were prepared using an average price for oil and natural gas on the first day of each month for the prior twelve months as required by the SEC.

Producer imbalances. We account for natural gas production imbalances using the sales method, whereby we recognize revenue on all natural gas sold to our customers regardless of our proportionate working interest in a well. Liabilities are recorded for imbalances greater than our proportionate share of remaining estimated natural gas reserves. Our aggregate imbalance positions at March 31, 2018, and December 31, 2017, were immaterial.

Income taxes

In December 2017, the President of the United States signed into law the Tax Cuts and Jobs Act of 2017 (the "Act"), making significant changes to the Internal Revenue Code. Changes include, but are not limited to, a federal corporate tax rate of 21%, additional limitations on executive compensation, and limitations on the deductibility of interest. The FASB issued Accounting Standards Update ("ASU") 2018-05, Income Taxes (Topic 740): "Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin ("SAB") No. 118" to address the application of GAAP in situations when a registrant does not have the necessary information available, prepared, or analyzed (including computations) in reasonable detail to complete the accounting for certain income tax effects of the Act.

As of March 31, 2018, we had not completed our accounting with regard to Section 162(m) provisions under the Act, and anticipate completing our analysis prior to filing our 2017 tax return in the third quarter of 2018, which is within the one year measurement period required under SAB 118. As such, we have not made an adjustment to the provisional tax benefit recorded under SAB 118 at December 31, 2017. We have estimated our provision for income taxes in accordance with the Act and guidance available as of the date of this filing.

Despite the Company's net loss for the quarter ended March 31, 2018 we did not record any net deferred tax benefit for the quarter ended March 31, 2018, as any deferred tax asset arising from the benefit is reduced by a valuation allowance as utilization of the loss carryforwards and realization of other deferred tax assets cannot be reasonably assured.

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, as well as the jurisdiction in which such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of our industry.

We will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until we can determine that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead us to conclude that it is more likely than not that our net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in oil prices, and taxable events that could result from one or more transactions. The valuation allowance does not prevent future utilization of the tax attributes if we recognize taxable income. As long as we conclude that the valuation allowance against our net deferred tax assets is necessary, we likely will not have any additional deferred income tax expense or benefit.

The benefit of an uncertain tax position taken or expected to be taken on an income tax return is recognized in the consolidated financial statements at the largest amount that is more likely than not to be sustained upon examination by the relevant taxing authority. Interest and penalties, if any, related to uncertain tax positions would be recorded in interest expense and other expense, respectively. There were no uncertain tax positions at March 31, 2018, or December 31, 2017.

Elements of the Reorganization Plan provided that our indebtedness related to Senior Notes and certain general unsecured claims were exchanged for Successor common stock in settlement of those claims. Absent an exception, a debtor recognizes cancellation of indebtedness income ("CODI") upon discharge of its outstanding indebtedness for an amount of consideration that is less than its adjusted issue price. The Internal Revenue Code of 1986, as amended ("IRC"), provides that a debtor in a Chapter 11 bankruptcy case may exclude CODI from taxable income but must reduce certain of its tax attributes by the amount of any CODI realized as a result of the consummation of a plan of reorganization. The amount of CODI realized by a taxpayer is determined based on the fair market value of the consideration received by the creditors in settlement of outstanding indebtedness. As a result of the market value of equity upon emergence from Chapter 11 bankruptcy proceedings, the estimated amount of CODI is approximately $61,000, which will reduce the value of the Company's net operating losses. The actual reduction in tax attributes does not occur until the first day of the Company's tax year subsequent to the date of emergence, or January 1, 2018. The reduction of net operating losses is expected to be fully offset by a corresponding decrease in valuation allowance.

The IRC provides an annual limitation with respect to the ability of a corporation to utilize its tax attributes, as well as certain built-in-losses, against future taxable income in the event of a change in ownership. Emergence from Chapter 11 bankruptcy proceedings resulted in a change in ownership for purposes of the IRC Section 382. We analyzed alternatives available within the IRC to taxpayers in Chapter 11 bankruptcy proceedings in order to minimize the impact of the ownership change and CODI on our tax attributes. Upon filing our 2017 U.S. Federal income tax return, we plan to elect an available alternative which would likely result in the Company experiencing a limitation that subjects existing tax attributes at emergence to an IRC Section 382 limitation that could result in some or all of the remaining net operating loss carryforwards expiring unused. However, we will continue to evaluate the remaining available alternatives which would not subject existing tax attributes to an IRC Section 382 limitation.

Loss on asset sale.

In November 2017, we closed on the sale of our EOR assets. In conjunction with this divestiture, we recorded a loss on sale of $25,163 during the fourth quarter of 2017, which was computed based on preliminary closing estimates. As a result of the final closing adjustments on the sale, we recorded an additional loss of $1,064 during the first quarter of 2018.

Other

Other includes certain expenses related to our restructuring and subleasing activities.

Restructuring. We incurred exit costs in conjunction with our EOR asset divestiture, which are predominantly comprised of one-time severance and termination benefits for the affected employees. During the three months ended March 31, 2018, we recorded $425 of expense as a result of termination benefits for the final slate of employees terminated as a result of the divestiture.

Subleases. Prior to the sale of our EOR assets in November 2017, we utilized CO_2 compressors that were considered integral to our EOR operations and were leased under six lease agreements from U.S. Bank. In conjunction with the sale, we continued to lease the compressors, but executed sublease agreements with the purchaser of our EOR assets (the “Sublessee”). Minimum payments under the subleases are equal to the original leases and hence we did not record any losses upon initiation of the subleases. Of the original lease agreements, three are classified as capital leases while the remaining three are classified as operating leases. Prior to the asset sale, the capital leases were included in our full cost amortization base and hence subject to amortization on a units-of-production basis, while also incurring interest expense. The payments under our operating leases were previously recorded as “Lease operating expense” in our statement of operations. All the subleases have been classified as operating leases from a lessor’s standpoint. Subsequent to the execution of the subleases, all payments received from the Sublessee are reflected as revenues on our statement of operations. Payments we make to U.S. Bank on the original operating leases, which were $403 for the three months ended March 31, 2018, are reflected in “Other” on our statement of operations. With respect to the capital leases, we have reclassified the amount associated with these leases from the full cost amortization base to plant, property and equipment on our balance sheet and are amortizing the asset on a straight line basis prospectively. We will continue incurring interest expense on the capital leases. Our sublease revenue is not within the scope of the new revenue recognition guidance discussed below.

Joint Venture

On September 25, 2017, we entered into a joint development agreement (“JDA”) with BCE Roadrunner LLC, a wholly-owned subsidiary of Bayou City Energy Management, LLC (“BCE”), pursuant to which BCE will fund 100 percent of our drilling, completion and equipping costs associated with 30 joint venture STACK wells, subject to average well cost caps that vary by well-type across location and targeted formations, approximately between $3,400 and $4,000 per gross well. The JDA wells, which will be drilled and operated by us, include 17 wells in Canadian County and 13 wells in Garfield County. The JDA provides us with a means to accelerate the delineation of our position within our Garfield and Canadian County acreage, realizing further efficiencies and holding additional acreage by production, and potentially adding reserves. In exchange for funding, BCE will receive wellbore-only interest in each well totaling an 85% carve-out working interest from our original working interest (and we retain 15%) until the program reaches a 14% internal rate of return. Once achieved, ownership interest in all JDA wells will revert such that we will own a 75% working interest and BCE will retain a 25% working interest. We will retain all acreage and reserves outside of the wellbore, with both parties entitled to revenues and paying lease operating expenses based on their working interest.

(dollars in thousands, except per share amounts)

Cost reduction initiatives

Cost reduction initiatives include expenses related to our efforts to reduce our capital, operating and administrative costs in response to the depressed commodity pricing environment. The expense consists of costs for one-time severance and termination benefits in connection with our reductions in force and third party legal and professional services we have engaged to assist in our cost savings initiatives as follows:

	Successor	Predecessor
	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
One-time severance and termination benefits	$ 1	$ 608
Professional fees	5	21
Total cost reduction initiatives expense	$ 6	$ 629

Reorganization items

Reorganization items reflect, where applicable, expenses, gains and losses incurred that are incremental and a direct result of the reorganization of the business. As a result of our emergence from bankruptcy, we have also recorded gains on the settlement of liabilities subject to compromise and gains from restating our balance sheet to fair values under fresh start accounting. "Professional fees" in the table below for periods subsequent to the Effective Date are comprised of legal fees for continuing work to resolve outstanding bankruptcy claims and fees to the U.S. Bankruptcy Trustee, which we will continue to incur until our bankruptcy case is closed. Reorganization items are as follows:

	Successor		Predecessor
	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Loss (gain) on the settlement of liabilities subject to compromise	$ 48	$ —	$ (372,093)
Fresh start accounting adjustments	—	—	(641,684)
Professional fees	989	620	18,790
Rejection of employment contracts	—	—	4,573
Write off unamortized issuance costs on Prior Credit Facility	—	—	1,687
Total reorganization items	$ 1,037	$ 620	$ (988,727)

Recently adopted accounting pronouncements

In May 2014, the FASB issued authoritative guidance that supersedes previous revenue recognition requirements and requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Please see "Note 5—Revenue recognition" for our disclosure regarding adoption of this update.

In January 2017, the FASB issued authoritative guidance that changes the definition of a business to assist entities with evaluating when a set of transferred assets and activities constitutes a business. The guidance requires an entity to evaluate if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets; if so, the set of transferred assets and activities is not a business. The guidance also requires a business to include at least one substantive process and narrows the definition of outputs by more closely aligning it with how outputs are described under updated revenue recognition guidance. The guidance is effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those years. We adopted this update effective January 1, 2018, without a material impact to our financial statements. We expect that the new guidance, when applied to the facts and circumstances of a future transaction, may impact the likelihood whether a future transaction would be accounted for as a business combination.

In January 2016, the FASB issued authoritative guidance that amends existing requirements on the classification and measurement of financial instruments. The standard principally affects accounting for equity investments and financial liabilities where the fair value option has been elected. The guidance is effective for fiscal years beginning after December 15, 2017, and interim periods thereafter. We adopted this update effective January 1, 2018, with no material impact to our financial statements or results of operations.

In August 2016, the FASB issued authoritative guidance which provides clarification on how certain cash receipts and cash payments are presented and classified on the statement of cash flows. This update provides guidance on eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies including bank-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The guidance is effective for fiscal years beginning after December 15, 2017, and is required to be adopted using a retrospective approach if practicable. We adopted this update effective January 1, 2018, without a material impact on our financial statements or results of operations.

In November 2016, the FASB issued authoritative guidance requiring that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The guidance is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years and should be applied using a retrospective transition method to each period presented. We adopted this update effective January 1, 2018, with no material impact to our financial statements or results of operations.

Recently issued accounting pronouncements

In February 2016, the FASB issued authoritative guidance significantly amending the current accounting for leases. Under the new provisions, all lessees will report a right-of-use asset and a liability for the obligation to make payments for all leases with the exception of those leases with a term of 12 months or less. Furthermore, all leases will fall into one of two categories: (i) a financing lease or (ii) an operating lease. Lessor accounting remains substantially unchanged with the exception that no leases entered into after the effective date will be classified as leveraged leases. For sale leaseback transactions, a sale will only be recognized if the criteria in the new revenue recognition standard are met. For public business entities, this guidance is effective for fiscal periods beginning after December 15, 2018 and interim periods thereafter, and should be applied using a modified retrospective approach. Early adoption is permitted. Our current operating leases are predominantly comprised of a limited number of leases for CO_2 compressors. However, we also enter into contractual arrangements relating to rights of ways or surface use that are typical of upstream oil and gas operations. We are currently assessing whether such arrangements are included in the new guidance, especially in light of a guidance update issued in January 2018 which provides a practical expedient on land easements. The land easement practical expedient allows an entity to continue its legacy accounting policy for land easements that exist or expire before the new standard's effective date and which are not accounted for under the current lease standard. We are in the process of evaluating the impact of this guidance on our consolidated financial statements and related disclosures and as contracts are reviewed under the new standard, this analysis could result in an impact to our financial statements; however, that impact is currently not known.

In June 2016, the FASB issued authoritative guidance which modifies the measurement of expected credit losses of certain financial instruments. The guidance is effective for fiscal years beginning after December 15, 2020, however early adoption is permitted for fiscal years beginning after December 15, 2018. The updated guidance impacts our financial statements primarily due to its effect on our accounts receivables. Our history of accounts receivable credit losses almost entirely relates to receivables from joint interest owners in our operated oil and natural gas wells. Based on this history and on mitigating actions we are permitted to take to offset potential losses such as netting past due amounts against revenue and assuming title to the working interest, we do not expect this guidance to materially impact our financial statements or results of operations.

Note 2: Earnings per share

We have not historically presented earnings per share ("EPS") because our common stock did not previously trade on a public market, either on a stock exchange or in the over-the-counter ("OTC") market. Accordingly, we were permitted under accounting guidance to omit such disclosure. However, the OTCQB tier of the OTC Markets Group Inc. began quoting our Class A common stock on May 26, 2017, under the symbol "CHPE". From May 18, 2017, through May 25, 2017, our Class A common stock was quoted on the OTC Pink marketplace under the symbol "CHHP". Our Class B common stock is not listed or quoted on the OTCQB or any other stock exchange or quotation system. Our Class A and Class B common stock shares equally in dividends and undistributed earnings. We are presenting basic and diluted EPS for all Successor periods subsequent to our emergence from bankruptcy but are not presenting EPS for any Predecessor period.

We are required under accounting guidance to compute EPS using the two-class method which considers multiple classes of common stock and participating securities. All securities that meet the definition of a participating security are to be included in the computation of basic EPS under the two-class method.

A reconciliation of the components of basic and diluted EPS is presented below:

(in thousands, except share and per share data)	Three months ended March 31, 2018
Numerator for basic and diluted earnings per share	
Net loss	$ (11,442)
Denominator for basic earnings per share	
Weighted average common shares - Basic for Class A and Class B	45,143,297
Denominator for diluted earnings per share	
Weighted average common shares - Diluted for Class A and Class B	45,143,297
Earnings per share	
Basic for Class A and Class B	$ (0.25)
Diluted for Class A and Class B	$ (0.25)
Participating securities excluded from earnings per share calculations	
Unvested restricted stock awards (2)	1,589,332
Antidilutive securities excluded from earnings per share calculations	
Warrants (1)	140,023

(1) The warrants to purchase shares of our Class A common stock are antidilutive due to the exercise price exceeding the average price of our Class A shares for the periods presented and due to the net losses we incurred.
(2) Our unvested restricted stock awards are considered to be participating securities as they include non-forfeitable dividend rights in the event a dividend is paid on our common stock. Our participating securities do not participate in undistributed net losses because they are not contractually obligated to do so and hence are not included in the computation of EPS in periods when a net loss occurs.

Note 3: Supplemental disclosures to the consolidated statements of cash flows

	Successor		Predecessor
	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Net cash provided by operating activities included:			
Cash payments for interest	$ 2,206	$ 2,768	$ 4,105
Interest capitalized	(1,521)	(54)	(248)
Cash payments for interest, net of amounts capitalized	$ 685	$ 2,714	$ 3,857
Cash payments for reorganization items	$ 410	$ —	$ 11,405
Non-cash investing activities included:			
Asset retirement obligation additions and revisions	$ 213	$ —	$ 716
Change in accrued oil and gas capital expenditures	$ 705	$ —	$ 5,387

Note 4: Debt and capital leases

As of the dates indicated, long-term debt and capital leases consisted of the following:

	March 31, 2018	December 31, 2017
New Credit Facility	$ 206,100	$ 127,100
Real estate mortgage note	9,031	9,177
Capital lease obligations	13,699	14,361
Unamortized debt issuance costs	(5,682)	(5,979)
Total debt, net	223,148	144,659
Less current portion	3,306	3,273
Total long-term debt, net	$ 219,842	$ 141,386

New Credit Facility

The New Credit Facility is a $400,000 facility collateralized by our oil and natural gas properties and is scheduled to mature on December 21, 2022. Availability under our New Credit Facility is subject to a borrowing base based on the value of our oil and natural gas properties and set by the banks semi-annually on May 1 and November 1 of each year. Availability on the New Credit Facility as of March 31, 2018, after taking into account outstanding borrowings and letters of credit on that date, was $78,072.

As of March 31, 2018, our outstanding borrowings were accruing interest at the Adjusted LIBO Rate (as defined in the New Credit Facility), plus the Applicable Margin (as defined in the New Credit Facility), which resulted in a weighted average interest rate of 4.86%.

The New Credit Facility contains financial covenants that require, for each fiscal quarter, we maintain: (1) a Current Ratio (as defined in the New Credit Facility) of no less than 1.00 to 1.00, and (2) a Ratio of Total Debt to EBITDAX (as defined in the New Credit Facility) of no greater than 4.0 to 1.0 calculated on a trailing four-quarter basis. We were in compliance with these financials covenants as of March 31, 2018.

The New Credit Facility contains covenants and events of default customary for oil and natural gas reserve-based lending facilities. Please see "Note 8—Debt" in Item 8 Financial Statements and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2017, for a discussion of the material provisions of our New Credit Facility.

Effective May 9, 2018, we entered into the First Amendment to the Tenth Restated Credit Agreement, among the Company and its subsidiaries, as borrowers, certain financial institutions party thereto, as lenders, and JPMorgan Chase Bank, N.A., as administrative agent (the "Amendment"). The Amendment reaffirmed our borrowing base at the same level of $285,000. In addition, the Amendment provided us with: (i) an increase from $150,000 to $250,000 to the aggregate amount of secured debt allowed, (ii) a waiver on the automatic reduction to the borrowing base calculation for the issuance of up to $300,000 in unsecured debt, (iii) the ability to offset the total debt calculation in the financial covenant calculations by up to $50,000 of unrestricted cash and cash equivalents whenever we do not have outstanding borrowings on the facility, and (iv) permission to make payments on account of the purchase, redemption, retirement, acquisition, cancellation or termination of our equity of up to $50,000.

Capital Leases

In 2013, we entered into lease financing agreements with U.S. Bank for $24,500 through the sale and subsequent leaseback of existing compressors owned by us. The carrying value of these compressors is included in our oil and natural gas full cost pool. The lease financing obligations are for 84-month terms and include the option to purchase the equipment for a specified price at 72 months as well as an option to purchase the equipment at the end of the lease term for its then-current fair market value. Lease payments related to the equipment are recognized as principal and interest expense based on a weighted average implicit interest rate of 3.8%. Minimum lease payments are approximately $3,181 annually. In conjunction with the sale of our EOR assets, these compressors were subleased to the buyer of those assets although we remain the primary obligor in relation to U.S. Bank.

Note 5: Revenue Recognition

In May 2014, the FASB issued authoritative guidance that supersedes previous revenue recognition requirements which has been codified as Accounting Standards Codification 606: Revenue from Contracts with Customers ("ASC 606"). ASC 606 requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.

Description of products and revenue disaggregation

Our revenue is predominantly derived from the production and sale of oil, natural gas and NGLs which, prior to January 1, 2018, was reported in the aggregate as "Commodity sales" on our statement of operations. Substantially all our oil and natural gas properties are located in Oklahoma and Texas and are sold to midstream gas processing plants or crude oil refineries in the vicinity. We have disaggregated revenue based on the separate commodities being sold: crude oil, natural gas and NGLs. In selecting the disaggregation categories, we considered a number of factors such as those affecting supply and demand and thus market prices, storage and the ability to transport the product, industry specific disclosures required by the SEC and FASB, other external disclosures we typically make, and information we have historically presented in the management discussion and analysis section of our annual and quarterly reports. As such, we believe that disaggregating revenue by commodity type appropriately depicts how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors.

The following table displays the revenue disaggregated and reconciles the disaggregated revenue to the revenue reported:

(in thousands)	Three months ended March 31, 2018
Revenues:	
Oil	$ 43,050
Natural gas	8,736
Natural gas liquids	9,591
Gross commodity sales	61,377
Transportation and processing	(3,488)
Net commodity sales	57,889

Performance Obligations

Our oil, natural gas and natural gas liquids contracts typically contain only one type of performance obligation, which is for the delivery of the underlying commodity, and which is satisfied at the point in time the commodity is transferred to the customer. We consider each commodity (ex. barrel of oil or MMBtu of natural gas) to be a separate performance obligation. For natural gas and natural gas liquids, all our sales are to midstream processing entities engaged in the processing of gas and marketing the resulting residue gas and NGLs to third party customers. We transfer control of the product to the midstream processing customer at the wellhead and recognize revenue upon such delivery.

Under our oil sales contracts, we generally sell oil to the purchaser from storage tanks near the wellhead and collect a contractually agreed upon index price, net of pricing differentials. We transfer control of the product from the storage tanks to the purchaser and recognize revenue based on the contract price.

We do not engage in activities to purchase and sell third party natural gas and NGLs. As a result, the commodity revenues we recognize are only for our working interest share of the production.

Pricing and measurement

All of our contracts use market or index-based pricing resulting in the entire transaction price being variable. Since our sales transactions meet the variable allocation criteria in the standard, all consideration is allocated entirely to performance obligations satisfied by distinct commodity units delivered. We record revenue in the month production is delivered to the purchaser. However, settlement statements for our commodity sales are received one to three months after the date production is delivered, and as a result, we are required to estimate the amount of production that was 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 for product sales in the month that payment is received from the purchaser. Historically, differences between our revenue estimates and actual revenue received have not been significant. We receive payment for a majority of our sales receivables in the month following delivery and substantially all within three months following delivery. For the three months ended March 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Transaction Price Allocated to Remaining Performance Obligations

For our product sales that have a contract term greater than one year, we have utilized the practical expedient in ASC 606, which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Since each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. For our product sales that have a contract term of one year or less, we have utilized the practical expedient in ASC 606, 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.

Nature of gas contracts

All our natural gas and NGL production is sold to midstream processing entities and we do not elect to take our residue gas and/or NGLs in-kind at the tailgate of processing plant. The midstream customer provides us with services such as compressing the gas, transporting the gas to the processing plant and processing it into the separate commodity streams for fees which are deducted from the revenue we receive. We previously reported fees for these services as "Transportation and processing" expenses in our statement of operations. Under ASC 606, since control and possession of the gas is transferred to the customer at the wellhead prior to the receipt of the aforementioned services, the customer is not deemed to be providing a distinct service and any fees paid to the customer are accounted for as a reduction in revenue. We have presented transportation and processing fees as a revenue deduction for the fiscal period beginning January 1, 2018, while our presentation for prior periods remains unchanged

Contract assets and liabilities

We recognize a receivable for the unconditional right to receive consideration when the commodity is transferred to the customer, at which point the performance obligation is satisfied. All our contract assets are in the form of receivables which are presented as "Accrued commodity sales" in our tabular disclosure of accounts receivable in Note 1—Nature of operations and summary of significant accounting policies. Since we are not entitled to advance payments from our customers prior to the transfer of our commodities nor do receive such payments, we do not have contract liabilities.

Method of adoption

We adopted ASC 606 effective January 1, 2018 using the modified retrospective approach. Based on an assessment of our contracts, the new guidance did not have a material impact on prior net income and therefore we did not record a cumulative effect adjustment to the opening balance of accumulated deficit.

Reconciliation of Income Statement

In accordance with ASC 606, the disclosure of the impact of adoption on our income statement is as follows:

	Three months ended March 31, 2018		
(in thousands)	**As reported**	**Balances without adoption of ASC 606**	**Effect of change**
Revenues			
Net commodity sales	$ 57,889	$ 61,377	$ (3,488)
Costs and expenses			
Transportation and processing	$ —	$ (3,488)	$ 3,488

Note 6: Derivative instruments

Overview

Our results of operations, financial condition and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil, natural gas and natural gas liquids. These commodity prices are subject to wide fluctuations and market uncertainties. To mitigate a portion of this exposure, we enter into various types of derivative instruments, including commodity price swaps, collars, put options, enhanced swaps and basis protection swaps. See "Note 9—Derivative Instruments" in Item 8. Financial Statement and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2017, for a description of the various kinds of derivatives we may enter into.

(dollars in thousands, except per share amounts)

The following table summarizes our crude oil derivatives outstanding as of March 31, 2018:

Period and type of contract	Volume MBbls	Weighted average fixed price per Bbl: Swaps	Purchased puts	Sold calls
2018				
Swaps	1,576	$ 58.14	$ —	$ —
Collars	138	$ —	$ 50.00	$ 60.50
2019				
Swaps	1,312	$ 54.26	$ —	$ —
2020				
Swaps	1,548	$ 49.54	$ —	$ —
2021				
Swaps	543	$ 44.34	$ —	$ —

The following table summarizes our natural gas derivatives outstanding as of March 31, 2018:

Period and type of contract	Volume BBtu	Weighted average fixed price per MMBtu
2018		
Swaps	7,911	$ 2.87
2019		
Swaps	7,632	$ 2.81
2020		
Swaps	3,600	$ 2.77

In February 2018, we renegotiated the fixed pricing of certain crude oil swaps scheduled to settle during 2018 in exchange for entering crude oil swaps, scheduled to settle from 2020 through 2021, at lower-than-market pricing. The renegotiated swaps cover 1,086 MBbls and have a new fixed price of $60.00 per barrel, replacing the original weighted average fixed price of $54.80 per barrel. The new crude oil swaps scheduled to settle from 2020 through 2021 have weighted average fixed prices of $46.26 and $44.34 per barrel, respectively, and cover 543 MBbls each year.

Effect of derivative instruments on the consolidated balance sheets

All derivative financial instruments are recorded on the balance sheet at fair value. See "Note 7—Fair value measurements" for additional information regarding fair value measurements. The estimated fair values of derivative instruments are provided below. The carrying amounts of these instruments are equal to the estimated fair values.

	As of March 31, 2018			As of December 31, 2017		
	Assets	Liabilities	Net value	Assets	Liabilities	Net value
Natural gas derivative contracts	$ 1,120	$ (671)	$ 449	$ 1,332	$ (1,054)	$ 278
Crude oil derivative contracts	—	(25,832)	(25,832)	—	(13,404)	(13,404)
Total derivative instruments	1,120	(26,503)	(25,383)	1,332	(14,458)	(13,126)
Less:						
Netting adjustments (1)	1,120	(1,120)	—	1,332	(1,332)	—
Derivative instruments - current	—	(10,548)	(10,548)	—	(8,959)	(8,959)
Derivative instruments - long-term	$ —	$ (14,835)	$ (14,835)	$ —	$ (4,167)	$ (4,167)

(1) Amounts represent the impact of master netting agreements that allow us to net settle positive and negative positions with the same counterparty. Positive and negative positions with counterparties are netted only to the extent that they relate to the same current versus noncurrent classification on the balance sheet.

(dollars in thousands, except per share amounts)

Effect of derivative instruments on the consolidated statements of operations

We do not apply hedge accounting to any of our derivative instruments. As a result, all gains and losses associated with our derivative contracts are recognized immediately as "Derivative (losses) gains" in the consolidated statements of operations.

"Derivative (losses) gains" in the consolidated statements of operations are comprised of the following:

	Successor		Predecessor
	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Change in fair value of commodity price derivatives	$ (12,257)	$ (13,807)	$ 46,721
Settlements (paid) received on commodity price derivatives	(4,244)	1,692	1,285
Total derivative (losses) gains	$ (16,501)	$ (12,115)	$ 48,006

Note 7: Fair value measurements

Fair value is defined by the FASB 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. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, valuation models are applied. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instruments' complexity.

Fair value measurements are categorized according to the fair value hierarchy defined by the FASB. The hierarchical levels are based upon the level of judgment associated with the inputs used to measure the fair value of the assets and liabilities as follows:

- Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.
- Level 2 inputs include quoted prices for identical or similar instruments in markets that are not active and inputs other than quoted prices that are observable for the asset or liability.
- Level 3 inputs are unobservable inputs for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the asset or liability is categorized based on the lowest level input that is significant to the fair value measurement in its entirety. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment, and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

Recurring fair value measurements

As of March 31, 2018, and December 31, 2017, our financial instruments recorded at fair value on a recurring basis consisted of commodity derivative contracts (see "Note 6—Derivative instruments"). We had no Level 1 assets or liabilities. Our derivative contracts classified as Level 2 consisted of commodity price swaps which are valued using an income approach. Future cash flows from the commodity price swaps are estimated based on the difference between the fixed contract price and the underlying published forward market price. Our derivative contracts classified as Level 3 consisted of collars. The fair value of these contracts is developed by a third-party pricing service using a proprietary valuation model, which we believe incorporates the assumptions that market participants would have made at the end of each period. Observable inputs include contractual terms, published forward pricing curves, and yield curves. Significant unobservable inputs are implied volatilities. Significant increases (decreases) in implied volatilities in isolation would result in a significantly higher (lower) fair value measurement. We review these valuations and the changes in the fair value measurements for reasonableness. All derivative instruments are recorded at fair value and include a measure of our own nonperformance risk for derivative liabilities or our counterparty credit risk for derivative assets.

(dollars in thousands, except per share amounts)

The fair value hierarchy for our financial assets and liabilities is shown by the following table:

	As of March 31, 2018			As of December 31, 2017		
	Derivative assets	Derivative liabilities	Net assets (liabilities)	Derivative assets	Derivative liabilities	Net assets (liabilities)
Significant other observable inputs (Level 2)	$ 1,120	$ (25,884)	$ (24,764)	$ 1,332	$ (14,163)	$ (12,831)
Significant unobservable inputs (Level 3)	—	(619)	(619)	—	(295)	(295)
Netting adjustments (1)	(1,120)	1,120	—	(1,332)	1,332	—
	$ —	$ (25,383)	$ (25,383)	$ —	$ (13,126)	$ (13,126)

(1) Amounts represent the impact of master netting agreements that allow us to net settle positive and negative positions with the same counterparty. Positive and negative positions with counterparties are netted on the balance sheet only to the extent that they relate to the same current versus noncurrent classification.

Changes in the fair value of our derivative instruments, classified as Level 3 in the fair value hierarchy, were as follows for the periods presented:

	Successor		Predecessor
Net derivative assets (liabilities)	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Beginning balance	$ (295)	$ 715	$ (98)
Realized and unrealized (losses) gains included in derivative (losses) gains	(432)	(239)	813
Settlements paid	108	—	—
Ending balance	$ (619)	$ 476	$ 715
(Losses) gains relating to instruments still held at the reporting date included in derivative (losses) gains for the period	$ (380)	$ (239)	$ 813

Nonrecurring fair value measurements

Asset retirement obligations. Additions to the asset and liability associated with our asset retirement obligations are measured at fair value on a nonrecurring basis. Our asset retirement obligations consist of the estimated present value of future costs to plug and abandon or otherwise dispose of our oil and natural gas properties and related facilities. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, inflation rates, discount rates, and well life, all of which are Level 3 inputs according to the fair value hierarchy. The estimated future costs to dispose of properties added during the first three months of 2018 and 2017 were escalated using an annual inflation rate of 2.26% and 2.30%, respectively. The estimated future costs to dispose of properties added during the three months ended March 31, 2018, were discounted, depending on the economic remaining estimated life of the property or the expected timing of the plugging and abandonment activity, with a credit-adjusted risk-free rate ranging from 6.92% to 7.15%. For the properties added during the period from March 22, 2017, through March 31, 2017, a credit-adjusted risk-free rate range from 5.20% to 7.40% was used. These estimates may change based upon future inflation rates and changes in statutory remediation rules. See "Note 8—Asset retirement obligations" for additional information regarding our asset retirement obligations.

Fair value of other financial instruments

Our significant financial instruments, other than derivatives, consist primarily of cash and cash equivalents, accounts receivable, accounts payable, and debt. We believe the carrying values of cash and cash equivalents, accounts receivable, and accounts payable approximate fair values due to the short-term maturities of these instruments.

The carrying value and estimated fair value of our debt were as follows:

	March 31, 2018		December 31, 2017	
Level 2	Carrying value (1)	Estimated fair value	Carrying value (1)	Estimated fair value
New Credit Facility	$ 206,100	$ 206,100	$ 127,100	$ 127,100
Other secured debt	9,031	9,031	9,177	9,177

(1) The carrying value excludes deductions for debt issuance costs.

The carrying value of our New Credit Facility and other secured long-term debt approximates fair value because the rates are comparable to those at which we could currently borrow under similar terms, are variable and incorporate a measure of our credit risk.

(dollars in thousands, except per share amounts)

Counterparty credit risk

Our derivative contracts are executed with institutions, or affiliates of institutions, that are parties to our credit facilities at the time of execution, and we believe the credit risks associated with all of these institutions are acceptable. We do not require collateral or other security from counterparties to support derivative instruments. Master agreements are in place with each of our derivative counterparties which provide for net settlement in the event of default or termination of the contracts under each respective agreement. As a result of the netting provisions, our maximum amount of loss under derivative transactions due to credit risk is limited to the net amounts due from the counterparties under the derivatives. Our loss is further limited as any amounts due from a defaulting counterparty that is a Lender, or an affiliate of a Lender, under our credit facilities can be offset against amounts owed to such counterparty Lender. As of March 31, 2018, the counterparties to our open derivative contracts consisted of four financial institutions, of which all were lenders under our New Credit Facility.

The following table summarizes our derivative assets and liabilities which are offset in the consolidated balance sheets under our master netting agreements. It also reflects the amounts outstanding under our credit facilities that are available to offset our net derivative assets due from counterparties that are lenders under our credit facilities.

	Offset in the consolidated balance sheets			Gross amounts not offset in the consolidated balance sheets		
	Gross assets (liabilities)	Offsetting assets (liabilities)	Net assets (liabilities)	Derivatives (1)	Amounts outstanding under credit facilities (2)	Net amount
March 31, 2018						
Derivative assets	$ 1,120	$ (1,120)	$ —	$ —	$ —	$ —
Derivative liabilities	(26,503)	1,120	(25,383)	—	—	(25,383)
	$ (25,383)	$ —	$ (25,383)	$ —	$ —	$ (25,383)
December 31, 2017						
Derivative assets	$ 1,332	$ (1,332)	$ —	$ —	$ —	$ —
Derivative liabilities	(14,458)	1,332	(13,126)	—	—	(13,126)
	$ (13,126)	$ —	$ (13,126)	$ —	$ —	$ (13,126)

(1) Since positive and negative positions with a counterparty are netted on the balance sheet only to the extent that they relate to the same current versus noncurrent classification, these represent remaining amounts that could have been offset under our master netting agreements.
(2) The amount outstanding under our New Credit Facility that is available to offset our net derivative assets due from counterparties that are lenders under our New Credit Facility.

We did not post additional collateral under any of these contracts as all of our counterparties are secured by the collateral under our credit facilities. Payment on our derivative contracts could be accelerated in the event of a default on our New Credit Facility. The aggregate fair value of our derivative liabilities subject to acceleration in the event of default was $26,503 before offsets at March 31, 2018.

Note 8: Asset retirement obligations

The following table provides a summary of our asset retirement obligation activity:

	Three months ended March 31, 2018
Beginning balance	$ 35,990
Liabilities incurred in current period	48
Liabilities settled or disposed in current period	(385)
Revisions in estimated cash flows	165
Accretion expense	532
Ending balance	$ 36,350
Less current portion included in accounts payable and accrued liabilities	2,749
Asset retirement obligations, long-term	$ 33,601

(dollars in thousands, except per share amounts)

See “Note 7—Fair value measurements” for additional information regarding fair value assumptions associated with our asset retirement obligations.

Note 9: Deferred compensation

Cash Incentive Plan

We adopted the Long-Term Cash Incentive Plan (the “Cash LTIP”) on August 7, 2015. The Cash LTIP provides additional cash compensation to certain employees of the Company in the form of awards that generally vest in equal annual increments over a four-year period. Since the awards do not vary according to the value of the Company’s equity, the awards are not considered “stock-based compensation” under accounting guidance. We accrue for the cost of each annual increment over the period service is required to vest.

A summary of compensation expense for the Cash LTIP is presented below:

	Successor		Predecessor
	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Cash LTIP expense (net of amounts capitalized)	$ 95	$ 13	$ 5
Cash LTIP payments	17	—	42

As of March 31, 2018, the outstanding liability accrued for our Cash LTIP, based on requisite service provided, was $1,678.

2010 Equity Incentive Plan

Prior to the Effective Date, stock awards were granted under the Chaparral Energy, Inc. 2010 Equity Incentive Plan (the “2010 Plan”) which was implemented on April 12, 2010. The awards granted under the 2010 Plan consisted of shares that were subject to service vesting conditions and shares that were subject to market and performance vested conditions. As of result of our bankruptcy and subsequent emergence, all unvested restricted stock was cancelled on the Effective Date.

2017 Management Incentive Plan

Our Reorganization Plan authorized the issuance of seven percent of outstanding Successor common shares on a fully diluted basis toward a new management incentive plan. On August 9, 2017, we adopted the Chaparral Energy, Inc. Management Incentive Plan (the “MIP”). The MIP provides for the following types of awards: options, stock appreciation rights, restricted stock, restricted stock units, performance awards and other incentive awards. The aggregate number of shares of Class A common stock, par value $0.01 per share, reserved for issuance pursuant to the MIP was initially set at 3,388,832 subject to changes in the event additional shares of common stock are issued under our Reorganization Plan. The MIP contemplates that any award granted under the plan may provide for the earlier termination of restrictions and acceleration of vesting in the event of a Change in Control, as may be described in the particular award agreement.

Pursuant to the MIP, we have granted restricted stock to employees and members of our Board of Directors (the “Board”). Of the grants awarded to employees, 75% were comprised of shares that are subject to service vesting conditions (the “Time Shares”) and 25% were comprised of shares that are subject to performance vested conditions (the “Performance Shares”). All grants to the Board were Time Shares.

Both the Time and Performance Shares are classified as equity-based awards. Compensation cost is generally recognized and measured according to the grant date fair value of the awards which are based on the market price of our common stock currently trading on the OTCQB tier of the OTC Markets Group, Inc.

The Time Shares vest in equal annual installments over the three -year vesting period. The Performance Shares vest in three tranches annually according to performance conditions established each year which generally relate to profitability, drilling results and other strategic goals.

As of March 31, 2018, performance conditions had not been established for 2018 and 2019 and hence a grant date with respect to Performance Shares allocated to those tranches had not been established for accounting purposes and no expense was accrued for these awards during the three months ended March 31, 2018. Performance conditions for 2018 were subsequently established and approved by our Board in May 2018 and we have commenced recognizing expense for the related shares in the second quarter of 2018.

(dollars in thousands, except per share amounts)

A summary of our restricted stock activity pursuant to our MIP is presented below:

	Time Shares		Performance Shares	
	Weighted average grant date fair value ($ per share)	Restricted shares	Weighted average grant date fair value ($ per share)	Restricted shares
Unvested and outstanding at January 1, 2018 (1)	$ 20.11	1,403,626	$ 20.15	269,476
Granted	$ —	—	$ —	—
Vested	$ —	—	$ —	—
Forfeited	$ 20.05	(68,540)	$ 20.05	(15,230)
Unvested and outstanding at March 31, 2018	$ 20.12	1,335,086	$ 20.17	254,246

(1) The beginning balance of Performance Shares relate to tranches with performance goals for 2018 and 2019. As of March 31, 2018, the goals had not been approved and hence a grant date had not been established and requisite service has not begun.

Stock-based compensation cost

Compensation cost is calculated net of forfeitures. As allowed by recent accounting guidance, we will recognize the impact of forfeitures due to employee terminations on expense as they occur instead of incorporating an estimate of such forfeitures. For awards with performance conditions, we will assess the probability that a performance condition will be achieved at each reporting period to determine whether and when to recognize compensation cost.

A portion of stock-based compensation cost associated with employees involved in our acquisition, exploration, and development activities has been capitalized as part of our oil and natural gas properties. The remaining cost is reflected in lease operating and general and administrative expenses in the consolidated statements of operations. Stock-based compensation expense is as follows for the periods indicated:

	Successor		Predecessor
	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Stock-based compensation cost	$ 5,580	$ —	$ 194
Less: stock-based compensation cost capitalized	(957)	—	(39)
Stock-based compensation expense (credit)	$ 4,623	$ —	$ 155
Payments for stock-based compensation	$ 1,422	$ —	$ —

Based on a quarter end market price of $17.75 per share of our common stock, the aggregate intrinsic value of all restricted shares outstanding was $28,211 as of March 31, 2018. The payments disclosed in the table above for the three months ended March 31, 2018, were for repurchases of 63,919 shares for tax withholding related to a vesting that occurred on December 31, 2017. In April 2018, we repurchased an additional 181,946 shares for tax withholding for $3,220 on a vesting that occurred during the month. We do not expect to make any material repurchases of vested shares for the next 12 months. As of March 31, 2018, and December 31, 2017, accrued payroll and benefits payable included $0 and $0, respectively, for stock-based compensation costs expected to be settled within the next twelve months. Unrecognized stock-based compensation cost of approximately $12,567 as of March 31, 2018, is expected to be recognized over a weighted-average period of 1.6 years.

Note 10: Commitments and contingencies

Standby letters of credit ("Letters") available under our New Credit Facility are used in lieu of surety bonds with various organizations for liabilities relating to the operation of oil and natural gas properties. We had Letters outstanding totaling $828 as of March 31, 2018, and December 31, 2017. When amounts under the Letters are paid by the lenders, interest accrues on the amount paid at the same interest rate applicable to borrowings under the New Credit Facility. No amounts were paid by the lenders under the Letters; therefore, we paid no interest on the Letters during the three months ended March 31, 2018 or 2017.

Litigation and Claims

Chapter 11 Proceedings. Commencement of the Chapter 11 Cases automatically stayed many of the proceedings and actions against us noted below as well as other claims and actions that were or could have been brought prior to May 9, 2016, and the claims remain subject to bankruptcy court jurisdiction. In connection with the proofs of claim asserted during bankruptcy from the proceedings or actions below, we are unable to estimate the amounts that will be allowed through the Bankruptcy proceedings due to the complexity and number of legal and factual issues presented by the matters and uncertainties with respect to, amongst other things, the nature of the claims and defenses, the potential size of the classes, the scope and types of the properties and agreements involved, and the ultimate potential outcomes of the matters. As a result, no reserves were established within our liabilities in connection with the proceedings and actions described below. To the extent that any of these legal proceedings result in a claim being allowed against us, pursuant to the terms of the Reorganization Plan, such claims will be satisfied through the issuance of new stock in the Company or, if the amount is such claim is below the convenience class threshold, through cash settlement.

Naylor Farms, Inc., individually and as class representative on behalf of all similarly situated persons v. Chaparral Energy, L.L.C. On June 7, 2011, an alleged class action was filed against us in the United States District Court for the Western District of Oklahoma ("Naylor Trial Court") alleging that we improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners as categorized in the petition from crude oil and natural gas wells located in Oklahoma. Plaintiffs indicated they seek damages in excess of $5,000, the majority of which would be comprised of interest and may increase with the passage of time. The purported class includes non-governmental royalty interest owners in oil and natural gas wells we operate in Oklahoma. The plaintiffs have alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and seek termination of leases, recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the alleged class. We responded to the Naylor Farms petition, denied the allegations and raised arguments and defenses. Plaintiffs filed a motion for class certification in October 2015. In addition, the plaintiffs filed a motion for summary judgment asking the court to determine as a matter of law that natural gas is not marketable until it is in the condition and location to enter an interstate pipeline. On May 20, 2016, we filed a Notice of Suggestion of Bankruptcy with the Naylor Trial Court.

On January 17, 2017, the Naylor Trial Court certified a modified class of plaintiffs with oil and gas leases containing specific language. The modified class constitutes less than 60% of the leases the plaintiffs originally sought to certify. After additional briefing on the subject, on April 18, 2017, the Naylor Trial Court issued an order certifying the class to include only claims relating back to June 1, 2006. On May 1, 2017, we filed a Petition for Permission to Appeal Class Certification Order with the Tenth Circuit Court of Appeals (the "Tenth Circuit"), which was granted. The appeal has been fully briefed, and oral arguments were held on March 20, 2018.

In addition to filing claims on behalf of the named and putative plaintiffs, on August 15, 2016, plaintiffs' attorneys filed a proof of claim on behalf of the putative class claiming damages in excess of $150,000 in our Chapter 11 Cases. The Company objected to treatment of the claim on a class basis, asserting the claim should be addressed on an individual basis. On April 20, 2017, plaintiffs filed an amended proof of claim reducing the claim to an amount in excess of $90,000 inclusive of actual and punitive damages, statutory interest and attorney fees. On May 24, 2017, the Bankruptcy Court denied the Company's objection, ruling the plaintiffs may file a claim on behalf of the class. This order did not establish liability or otherwise address the merits of the plaintiffs' claims, to which we will also object. On June 7, 2017 we appealed the Bankruptcy Court order to the United States District Court for the District of Delaware. Under the Reorganization Plan, the plaintiffs are identified as a separate class of creditors, Class 8. Class 8 claims are entitled to receive their pro rata share of new stock issued to the holders of general unsecured claims (including claims of the Noteholders). Although the members of Class 8 voted to reject the Plan, the Bankruptcy Court confirmed the Plan on March 10, 2017, without objection by the plaintiffs.

If the plaintiffs ultimately prevail on the merits of their claims, any liability arising under judgment or settlement of the unsecured claims would be satisfied through the issuance of new stock in the Company. We continue to dispute the plaintiffs' allegations, dispute the case meets the requirements for class certification, and are objecting to the claims both individually and on a class-wide basis.

Martha Donelson and John Friend, on behalf of themselves and on behalf of all similarly situated persons v. Chaparral Energy, L.L.C. On August 11, 2014, an alleged class action was filed against us, as well as several other operators in Osage County, in the United States District Court for the Northern District of Oklahoma, alleging claims on behalf of the named plaintiffs and all similarly situated Osage County land owners and surface lessees. The plaintiffs challenged leases and drilling permits approved by the Bureau of Indian Affairs without the environmental studies allegedly required under the National Environmental Policy Act (NEPA). The plaintiffs assert claims seeking recovery for trespass, nuisance, negligence and unjust enrichment. Relief sought includes declaring oil and natural gas leases and drilling permits obtained in Osage County without a prior NEPA study void *ab initio*, removing us from all properties owned by the class members, disgorgement of profits, and compensatory and punitive damages. On March 31, 2016, the Court dismissed the case against all defendants as an improper challenge under NEPA and the Administrative Procedures Act. On April 29, 2016, the plaintiffs filed motions to alter or amend the court's opinion and vacate the judgment, and to file an amended complaint to cure the deficiencies which the court found in the dismissed complaint. On May 20, 2016, the Company filed a Notice of Suggestion of Bankruptcy, and as a result has not responded to the plaintiffs' motions. After plaintiff's motion for reconsideration was denied, plaintiffs filed a Notice of Appeal with the Tenth Circuit Court of Appeals on December 6, 2016. Oral argument regarding the appeal was held on November 14, 2017, and on April 5, 2018, the Tenth Circuit affirmed the dismissal. The time to appeal the Tenth Circuit's ruling has not lapsed.

We anticipate any monetary liability related to this claim will be discharged. We dispute plaintiffs' allegations and dispute that the case meets the requirements for a class action.

Lisa West and Stormy Hopson, individually and as class representatives on behalf of all similarly situated persons v. Chaparral Energy, L.L.C. On February 18, 2016, an alleged class action was filed against us, as well as several other operators in the District Court of Pottawatomie County, State of Oklahoma, alleging claims on behalf of named plaintiffs and all similarly situated persons having an insurable real property interest in eight counties in central Oklahoma (the "Class Area"). The plaintiffs allege the oil and gas operations conducted by us and the other defendants have induced earthquakes in the Class Area. The plaintiffs did not seek damages for property damage, instead asked the court to require the defendants to reimburse plaintiffs and class members for earthquake insurance premiums from 2011 through the time at which the court determines there is no longer a risk of induced earthquakes, as well as attorney fees and costs and other relief. We responded to the petition, denied the allegations and raised a number of affirmative defenses. On March 18, 2016, the case was removed to the United States District Court for the Western District of Oklahoma under the Class Action Fairness Act. On May 20, 2016, we filed a Notice of Suggestion of Bankruptcy, informing the court that we had filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code. On October 14, 2016, the plaintiffs filed an Amended Complaint adding additional defendants and increasing the Class Area to 25 Central Oklahoma counties. Other defendants filed motions to dismiss the action which was granted on May 12, 2017. On July 18, 2017, plaintiffs filed a Second Amended Complaint adding additional named plaintiffs as putative class representatives and adding three additional counties to the putative class area. In the Second Amended Complaint, plaintiffs seek damages for nuisance, negligence, abnormally dangerous activities, and trespass. Due to Chaparral's bankruptcy, plaintiffs specifically limit alleged damages related to Chaparral's disposal activities occurring after our emergence from bankruptcy on March 21, 2017. We moved to dismiss the Second Amended Complaint on September 15, 2017.

Plaintiffs' attorneys filed a proof of claim on behalf of the putative class claiming in excess of $75,000 in our Chapter 11 Cases. We filed an objection to class treatment of the proof of claim filed by the West plaintiffs in our Bankruptcy proceeding. The Bankruptcy Court had a hearing on our objection and on February 9, 2018, the Bankruptcy Court granted our objection to class treatment of the proof of claim. We dispute the plaintiffs' claims, dispute that the case meets the requirements for a class action, dispute the remedies requested are available under Oklahoma law, and are vigorously defending the case.

Lisa Griggs and April Marler, on behalf of themselves and other Oklahoma citizens similarly situated v. New Dominion, L.L.C. et al. On July 21, 2017, an alleged class action was filed against us and other operators, in the District Court of Logan County, State of Oklahoma. The named plaintiffs assert claims on behalf of themselves and Oklahoma citizens owning a home or business between March 30, 2014, and the present in a Class Area which encompasses nine counties in central Oklahoma. The plaintiffs allege disposal of saltwater produced during oil and gas operations induced earthquakes in the Class Area, and each defendant has liability under theories of ultra-hazardous activities, negligence, nuisance, and trespass. On October 24, 2017, plaintiffs filed a First Amended Class Petition in Logan County, Oklahoma, adding Creek County, Oklahoma to the Class Area, and adding an additional earthquake to the list of seismic events allegedly caused by the defendants. The plaintiffs asked the court to award unspecified damages for damage to real and personal property and loss of market value, loss of use and enjoyment of the properties, and emotional harm, as well as punitive damages and pre-judgment and post-judgment interest. The case was removed to the Western District of Oklahoma on December 15, 2017, and on December 18, 2017, plaintiffs voluntarily dismissed us from the suit without prejudice. Due to subsequent remand to state court, we filed notice of the dismissal in the state court action on January 31, 2018.

James Butler et al. v. Berexco, L.L.C., Chaparral Energy, L.L.C, et al. On October 13, 2017, a group of fifty-two individual plaintiffs filed a lawsuit in the District Court of Payne County, State of Oklahoma against twenty-six named defendants, including us, and twenty-five unnamed defendants. Plaintiffs are all property owners and residents of Payne County, Oklahoma, and allege salt water disposal activities by the defendants, owners or operators of salt water disposal wells, induced earthquakes which have caused damage to real and personal property, and emotional damages. Plaintiffs claim absolute liability for ultra-hazardous activities, negligence, gross negligence, public and private nuisance, trespass, and ask for compensatory and punitive damages. On December 18, 2018, we moved the court to dismiss the claims against us. Prior to plaintiffs responding to our motion, a hearing on a motion to stay the Butler case was held on January 4, 2018. The judge granted the motion to stay proceedings, ruling from the bench that the Butler case was stayed pending final judgment or denial of class certification in the *Lisa West et al. v. ABC Oil Company, Inc.* case. Our motion to dismiss will not be considered until the stay is lifted, at which time, if necessary, we will dispute plaintiffs' claims, dispute that the remedies requested are available under Oklahoma law, and vigorously defend the case.

Lacheverjuan Bennett et al. v. Chaparral Energy, L.L.C., et al. On March 26, 2018, a group of twenty-seven individual plaintiffs filed a lawsuit in the District Court of Logan County, State of Oklahoma against twenty-three named defendants, including us, and twenty-five unnamed defendants. Plaintiffs are all property owners and residents of Logan County, Oklahoma, and allege the defendants, all oil and gas companies which have engaged in injection well operations, induced earthquakes which have caused damage to real and personal property, and caused emotional damages. Plaintiffs claim absolute liability for ultra-hazardous activities, negligence, gross negligence, public and private nuisance, and trespass, and ask for compensatory and punitive damages, and attorney fees and costs. Jointly with other defendants, we filed a motion to stay the proceedings pending resolution of related earthquake litigation. We dispute the plaintiffs' claims, dispute the remedies requested are available under Oklahoma law, and are vigorously defending the case.

We are involved in various other legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, employment claims, and other matters which arise in the ordinary course of business. In addition, other proofs of claim have been filed in our bankruptcy case which we anticipate repudiating. While the outcome of these legal proceedings cannot be predicted with certainty, we do not expect any of them individually to have a material effect on our financial condition, results of operations or cash flows.

We have numerous contractual commitments in the ordinary course of business including debt service requirements, operating leases, capital leases and purchase obligations. Our operating leases primarily relate to CO_2 compressors and office equipment while our capital leases are related to the sale and subsequent leaseback of CO_2 compressors. In conjunction with the sale of our EOR assets in November 2017, all CO_2 compressors were subleased to the buyer of those assets although we remain the primary obligor in relation to U.S. Bank. The subleases are structured such that the lease payments and remaining lease terms are identical to the original leases. Our purchase obligations as of March 31, 2018, include contracts for three drilling rigs with terms of less than one year. Other than the changes described herein and additional debt borrowings during the quarter, there were no material changes to our contractual commitments since December 31, 2017.

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

On May 9, 2016 (the "Petition Date"), Chaparral Energy, Inc. and its subsidiaries including Chaparral Energy, L.L.C., Chaparral Resources, L.L.C., Chaparral Real Estate, L.L.C., Chaparral CO2 , L.L.C., CEI Pipeline, L.L.C., CEI Acquisition, L.L.C., Green Country Supply, Inc., Chaparral Biofuels, L.L.C., Chaparral Exploration, L.L.C., Roadrunner Drilling, L.L.C. filed voluntary petitions seeking relief under Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court") commencing cases for relief under Chapter 11 of the Bankruptcy Code. On March 10, 2017, (the "Confirmation Date"), the Bankruptcy Court confirmed our Reorganization Plan and on March 21, 2017 (the "Effective Date"), the Reorganization Plan became effective and we emerged from bankruptcy. References to "Successor" relate to the financial position and results of operations of the reorganized company subsequent to the Effective Date while references to "Predecessor" relate to the financial position and results of operations prior to, and including the Effective Date.

The following discussion and analysis is intended to assist in understanding our financial condition and results of operations for the three months ended March 31, 2018 (Successor), the periods of March 22, 2017, through March 31, 2017 (Successor) and January 1, 2017, through March 21, 2017 (Predecessor). The information should be read in conjunction with our unaudited consolidated financial statements and the notes thereto included in this quarterly report as well as the information included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2017, though as described below, such prior financial statements may not be comparable to our interim financial statements due to the adoption of fresh-start accounting.

Statements in our discussion may be forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. For more information, see *"Cautionary Note Regarding Forward-Looking Statements."*

Overview

Chaparral Energy, Inc. is a Delaware corporation headquartered in Oklahoma City which has been engaged in the onshore oil and natural gas acquisition, exploitation, exploration and production business in the United States since 1988. We have transitioned from operating a diversified asset base in the Mid-Continent, which previously included CO_2 enhanced oil recovery assets, to a dedicated focus on the development and acquisition of unconventional oil and natural gas reserves in the STACK. Our STACK play is home to multiple oil-rich reservoirs including the Oswego, Meramec, Osage and Woodford formations.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas and on our ability to find, develop and acquire oil and natural gas reserves that are economically recoverable. The preparation of our financial statements in conformity with generally accepted accounting principles ("GAAP") requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and natural gas reserves. We use the full cost method of accounting for our oil and natural gas activities.

Our December 31, 2017, reserve estimates reflect that our production rate on current proved developed properties will decline at annual rates of approximately 22%, 15%, and 12% for the next three years. To grow our production and cash flow, we must find, develop and acquire new oil and natural gas reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and acquire oil and natural gas reserves.

Highlights

Our financial and operating performance in the first quarter of 2018 includes the following highlights:

- We incurred a net loss of $11.4 million which includes a $16.5 million loss on commodity derivatives.
- Our total net production of 1,737 MBoe for the three months ended March 31, 2018, decreased approximately 14% compared to net production for the period from January 1 – March 21 and March 22 – March 31, 2017, which totaled 2,023 MBoe. The decrease was primarily a result of the sale of our EOR assets in November 2017. Since production from our EOR assets was predominantly in crude oil as opposed to natural gas or NGLs, the divestiture resulted in a 40% decrease in crude oil production across the same time periods.
- Excluding production from divested EOR assets, net production increased 14% for the three months ended March 31, 2018, compared to net production for the three months ended March 31, 2017. The increase was driven by an increase in net production from our STACK play. Net production from our STACK play was 1,106 MBoe for the three months ended March 31, 2018, compared to net production for the three months ended March 31, 2017, of 735 MBoe, an increase of 50%. This pattern of growth underscores our sole focus on developing the STACK.

- Our gross commodity sales (excludes transportation and processing deductions) of $61.4 million for the three months ended March 31, 2018, decreased approximately 17% compared to gross commodity sales for the period from January 1 to March 21 and March 22 to March 31, 2017, which totaled $74.3 million. The percentage decrease in sales is greater than the percentage decrease in production as the production from our divested EOR assets was comprised primarily of crude oil, which had a higher realized price per Boe compared to natural gas and NGLs.
- In January 2018, we closed on a purchase of approximately 7,000 acres located in the core of our STACK Kingfisher County leasehold, in an area directly adjacent to producing properties we own, for a total purchase price of $60.6 million. This area is highly prospective for drilling in the Osage and Meramec formations of the STACK play.
- Our oil and natural gas capital expenditures for the three months ended March 31, 2018, was $101.8 million, approximately two-thirds of which was a result of acquisitions, including the 7,000 acre Kingfisher County leasehold purchase discussed above.

Capital development

We incurred capital expenditures of $101.8 million for the three months ended March 31, 2018. This included $65.8 million for acquisitions, which was expended mostly for the 7,000 acre Kingfisher Country leasehold purchase. We incurred $33.4 million on drilling and completions which included completing four wells drilled in the prior year, drilling and completing one well, drilling three wells scheduled for completion after the first quarter, and participating in wells operated by others. We are currently operating three horizontal drilling rigs in the STACK, of which one rig is deployed to drilling under our joint development agreement (discussed below). Our drilling activity in 2018 will encompass drilling wells in Kingfisher, Canadian and Garfield counties, in Oklahoma.

Joint development agreement

In 2017, we entered into a joint development agreement ("JDA") with BCE Roadrunner, LLC, a wholly-owned subsidiary of Bayou City Energy ("BCE"), pursuant to which BCE will fund 100 percent of our drilling, completion and equipping costs associated with 30 STACK wells subject to well cost caps that vary by well-type across location and targeted formations, ranging from $3.4 million to $4.0 million per gross well. The cost caps may be increased up to 20% by mutual agreement. The JDA wells, which will be drilled and operated by us, include 17 initially identified locations in Canadian County (in the Meramec and Woodford formations) and 13 initially identified locations in Garfield County (in the Osage and Meramec formations), with the option to expand the JDA to drill additional wells in the future. The JDA provides us with a means to accelerate the delineation of our position within our promising Garfield and Canadian County acreage, realizing further efficiencies and holding additional acreage with production, and potentially adding reserves. In exchange for funding, BCE will receive wellbore-only interest in each well totaling an 85% carve-out working interest from our original working interest (we will retain the remaining 15%) until the program reaches a 14% internal rate of return ("the hurdle rate"). Once achieved, ownership interest in all wells will revert such that we will own a 75% working interest and BCE will retain a 25% working interest. We will retain all acreage and reserves outside of the wellbore, with both parties paying their respective share of lease operating expenses. During the three months ended March 31, 2018, we drilled 10 wells, of which one was completed and nine scheduled for completion after the first quarter. As of March 31, 2018, we have drilled 14 wells under the JDA, of which four have been completed. We expect to drill substantially all the remaining JDA wells by the end of the year.

Price uncertainty and the full-cost ceiling impairment

Oil and natural gas prices fluctuate widely. We generally hedge a substantial portion of our expected future oil and natural gas production to reduce our exposure to commodity price decreases. The prices we receive for our oil and natural gas production affect our: (i) cash flow available for capital expenditures, (ii) ability to borrow and raise additional capital, (iii) ability to service debt, (iv) quantity of oil and natural gas we can produce, (v) quantity of oil and natural gas reserves, and (vi) operating results for oil and natural gas activities.

Recent commodity price improvement has increased our price per barrel of crude oil by approximately 24% during the first quarter of 2018 compared to the prior year quarter. In an environment of continued price volatility, the current price improvement trend could stall, or the industry could enter another downturn causing additional material negative impacts on our revenues, profitability, cash flows, liquidity, and current reserves, and we could consider further reductions in our capital program, additional asset sales or additional organizational changes.

We deal with volatility in commodity prices primarily by working to make our overall cost structure competitive and supportive in the current oil price environment. In addition, we maintain flexibility in our capital investment program with a diversified drilling portfolio and limited long-term commitments, which enables us to respond quickly to industry price volatility. We also deal with price volatility by hedging a substantial portion of our expected future oil and natural gas production to reduce our near term exposure to commodity price decreases. We currently have derivative contracts in place for a portion of oil and natural gas production from 2018 through 2021 (see Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Price volatility also impacts our business through the full cost ceiling test calculation. The ceiling test calculation dictates that we use the unweighted arithmetic average price of crude oil and natural gas as of the first day of each month for the 12-month period ending on the balance sheet date. Since the prices used in the cost ceiling are based on a trailing 12-month period, the full impact of price changes on our financial statements may not recognized immediately but could be spread over several reporting periods. A ceiling test write-down was not required for the first quarter of 2018. In addition to commodity prices, our production rates, levels of proved reserves, estimated future operating expenses, estimated future development costs, estimated fair value of unevaluated properties, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Results of operations

Production

Production volumes by area were as follows (MBoe):

	Successor		Predecessor
	Three months ended March 31, 2018	**Period from March 22, 2017 through March 31, 2017**	**Period from January 1, 2017 through March 21, 2017**
STACK Areas:			
STACK - Kingfisher County	677	55	423
STACK - Canadian County	249	13	142
STACK - Garfield County	145	8	57
STACK - Other	35	3	34
Total STACK Areas	1,106	79	656
EOR Areas	—	58	445
Other	631	90	695
Total	1,737	227	1,796

Our total net production of 1,737 MBoe for the three months ended March 31, 2018, decreased approximately 14% compared to net production for the period from January 1 – March 21 and March 22 – March 31, 2017, which totaled 2,023 MBoe. The decrease was primarily a result of the sale of our EOR assets in November 2017. Excluding production from divested EOR assets, net production increased 14% for the three months ended March 31, 2018, compared to net production for the period from January 1 – March 21 and March 22 – March 31, 2017. The increase was driven by an increase in net production from our STACK play. Net production from our STACK play was 1,106 MBoe for the three months ended March 31, 2018, compared to net production for the period from January 1 – March 21 and March 22 – March 31, 2017, which totaled 735 MBoe, an increase of 50%. This pattern of growth underscores our sole focus on developing the STACK.

Revenues and transportation and processing

Our commodity sales are derived from the production and sale of oil, natural gas and natural gas liquids. These revenues do not include the effects of derivative instruments and may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Effective January 1, 2018, we adopted new accounting guidance relating to revenue recognition. While our assessment of the new guidance did not indicate a material impact on prior and future net income, the new guidance requires us to classify certain costs for gathering, transportation and processing of gas as part of the transaction price rather than reported expense. Accordingly, amounts previously reported as “Transportation and processing” on our statement of operations are reflected as a revenue deduction as of the current quarter. Since we are adopting the new guidance using the modified retrospective approach, the reclassification of transportation and processing costs as a revenue deduction will be reflected prospectively while these charges will continue to be reflected as an expense on our statement of operations for fiscal periods prior to January 1, 2018.

The following table presents information about our production and commodity sales before the effects of commodity derivative settlements:

	Successor		Predecessor
	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Commodity sales (in thousands):			
Oil	$ 43,050	$ 6,230	$ 51,847
Natural gas	8,736	785	9,140
Natural gas liquids	9,591	793	5,544
Gross commodity sales	$ 61,377	$ 7,808	$ 66,531
Transportation and processing	(3,488)	—	—
Net commodity sales	$ 57,889	$ 7,808	$ 66,531
Production:			
Oil (MBbls)	697	134	1,036
Natural gas (MMcf)	3,788	344	3,046
Natural gas liquids (MBbls)	409	36	252
MBoe	1,737	227	1,796
Average daily production (Boe/d)	19,300	22,700	22,450
Average sales prices (excluding derivative settlements):			
Oil per Bbl	$ 61.76	$ 46.49	$ 50.05
Natural gas per Mcf	$ 2.31	$ 2.28	$ 3.00
NGLs per Bbl	$ 23.45	$ 22.03	$ 22.00
Transportation and processing per Boe	$ (2.01)	$ —	$ —
Average sales price per Boe	$ 33.33	$ 34.40	$ 37.04

Our gross commodity sales of $61.4 million for the three months ended March 31, 2018, decreased approximately 17% compared to gross commodity sales for the period from January 1 – March 21 and March 22 – March 31, 2017, which totaled $74.3 million. The decrease in sales is primarily the result of a 40% decrease in net crude oil production and lower natural gas prices partially offset by higher realized prices for crude oil and increased net production of natural gas and NGLs. The steep decline in crude oil production is due to the divestiture of our EOR assets in late 2017, where production from those assets was predominantly comprised of crude oil. In contrast, our STACK wells have a more balanced production mix of all three commodities and therefore growth in our STACK play has resulted in an increase in natural gas and NGL production.

	Three months ended March 31, 2018 vs. 2017	
(in thousands)	Sales change	Percentage change in sales
Change in oil sales due to:		
Prices	$ 8,452	14.5%
Production	$ (23,479)	(40.4)%
Total change in oil sales	$ (15,027)	(25.9)%
Change in natural gas sales due to:		
Prices	$ (2,354)	(23.7)%
Production	$ 1,165	11.7%
Total change in natural gas sales	$ (1,189)	(12.0)%
Change in natural gas liquids sales due to:		
Prices	$ 592	9.3%
Production	$ 2,662	42.0%
Total change in natural gas liquids sales	$ 3,254	51.3%

Transportation and processing revenue deductions principally consist of deductions by our customers for costs to prepare and transport production from the wellhead to a specified sales point and processing costs of gas into natural gas liquids. As previously discussed, due to the adoption of new accounting guidance, these charges are presented as a revenue deduction beginning January 1, 2018, whereas they continue to be reflected as an expense on our statement of operations for fiscal periods prior to January 1, 2018. Transportation and processing deductions were $3.5 million for the three months ended March 31, 2018, an increase of approximately

46% compared to deductions for the period from January 1 – March 21 and March 22 – March 31, 2017, which totaled $2.4 million. Transportation and processing deductions were higher on a dollar and per Boe basis as a result of increased gas volumes in our STACK area where we have experienced higher transportation and processing costs compared to our other operating areas. In addition, transportation and processing deductions were higher on a per Boe basis due to our EOR asset divestiture where production from the divested asset was substantially all in the form of crude oil with no associated transportation and processing fees. Transportation and processing deductions are higher in the STACK in part due to new infrastructure being built in the area. In addition, we are also experiencing higher per unit costs associated with our non-operated wells and a larger proportion of gas production subject to fee based processing arrangements as opposed to percentage of proceeds ("POP") arrangements.

	Successor		Predecessor
	Three months ended March 31, 2018 (1)	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Transportation and processing expenses (in thousands)	$ —	$ 361	$ 2,034
Transportation and processing expenses per Boe	$ —	$ 1.59	$ 1.13

(1) Transportation and revenue deductions for the three months ended March 31, 2018, were $3,488,000 or $2.01 per Boe.

Derivative activities

Our results of operations, financial condition and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties. To mitigate a portion of this exposure, we have entered into various types of derivative instruments, including commodity price swaps and costless collars.

We closely monitor the fair value of our derivative contracts and may elect to settle a contract prior to its scheduled maturity date in order to lock in a gain or loss.

Our realized prices are impacted by realized gains and losses resulting from commodity derivatives contracts. The following table presents information about the effects of derivative settlements on realized prices:

	Successor		Predecessor
	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Oil (per Bbl):			
Before derivative settlements	$ 61.76	$ 46.49	$ 50.05
After derivative settlements	$ 56.26	$ 59.12	$ 51.20
Post-settlement to pre-settlement price	91.1%	127.2%	102.3%
Natural gas (per Mcf):			
Before derivative settlements	$ 2.31	$ 2.28	$ 3.00
After derivative settlements	$ 2.20	$ 2.28	$ 3.03
Post-settlement to pre-settlement price	95.2%	100.0%	101.0%

The estimated fair values of our oil and natural gas derivative instruments are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

(in thousands)	March 31, 2018	December 31, 2017
Derivative (liabilities) assets:		
Crude oil derivatives	$ (25,832)	$ (13,404)
Natural gas derivatives	449	278
Net derivative (liabilities) assets	$ (25,383)	$ (13,126)

The effects of derivative activities on our results of operations and cash flows were as follows:

	Successor				Predecessor	
	Three months ended March 31, 2018		Period from March 22, 2017 through March 31, 2017		Period from January 1, 2017 through March 21, 2017	
(in thousands)	Non-cash fair value adjustment	Settlements (paid) received	Non-cash fair value adjustment	Settlements (paid) received	Non-cash fair value adjustment	Settlements (paid) received
Derivative (losses) gains:						
Crude oil derivatives	$ (12,429)	$ (3,840)	$ (13,650)	$ 1,692	$ 42,819	$ 1,192
Natural gas derivatives	172	(404)	(157)	—	3,902	93
Derivative (losses) gains	$ (12,257)	$ (4,244)	$ (13,807)	$ 1,692	$ 46,721	$ 1,285

We do not apply hedge accounting to any of our derivative instruments. As a result, all gains and losses associated with our derivative contracts are recognized immediately as “Derivative (losses) gains” in our consolidated statements of operations. The fluctuation in derivative (losses) gains from period to period is due primarily to the significant volatility of oil and natural gas prices and to changes in our outstanding derivative contracts during these periods.

In February 2018, we renegotiated the fixed pricing of certain crude oil swaps scheduled to settle during 2018 in exchange for entering crude oil swaps, scheduled to settle from 2020 through 2021, at lower-than-market pricing. The renegotiated swaps cover 1,086 MBbls and have a new fixed price of $60.00 per barrel, replacing the original weighted average fixed price of $54.80 per barrel. The new crude oil swaps scheduled to settle in 2020 and 2021 have weighted average fixed prices of $46.26 and $44.34 per barrel, respectively, and cover 543 MBbls each year. On February 7, 2018, the date we entered into the 2020 and 2021 swaps, the average 2020 and 2021 NYMEX strip price for crude oil was $52.68 and $50.83 per barrel, respectively.

Lease operating expenses

	Successor		Predecessor
(in thousands, except per Boe data)	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Lease operating expenses:			
STACK Areas	$ 5,941	$ 368	$ 2,247
EOR Areas	—	1,469	8,488
Other	8,602	2,422	9,206
Total lease operating expenses	$ 14,543	$ 4,259	$ 19,941
Lease operating expenses per Boe:			
STACK Areas	$ 5.37	$ 4.66	$ 3.43
EOR Areas	$ —	$ 25.33	$ 19.07
Other	$ 13.63	$ 26.91	$ 13.25
Lease operating expenses per Boe	$ 8.37	$ 18.76	$ 11.10

Lease operating expenses (“LOE”) are sensitive to changes in demand for field equipment, services, and qualified operational personnel, which is driven by demand for oil and natural gas. However, the timing of changes in operating costs may lag behind changes in commodity prices. Our EOR projects were historically more expensive to operate than traditional industry operations due to the nature of operations along with the costs of recovery and recycling of CO_2.

LOE is not comparable across the time periods presented above in part due to our recognition of bonus expense. Provisions set by the Bankruptcy Court during the pendency of our bankruptcy prevented us from paying bonuses in the ordinary course of business. Pursuant to these provisions, we did not accrue bonuses during the entire pendency of our bankruptcy. Upon emergence, we recognized expense for the entire amount of our 2016 fiscal year bonus (paid in March 2017) while also accruing a pro rata portion of our 2017 fiscal year bonus. We have accrued bonuses in the ordinary course of business subsequent to our emergence. The bonus expense component of lease operating expense is disclosed in the table below:

	Successor		Predecessor
(in thousands)	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Bonus expense	$ 189	$ 2,019	$ —

LOE for the three months March 31, 2018, of $14.5 million was lower compared to LOE for January 1 – March 21 and March 22 – March 31, 2017, which totaled $24.2 million due to the bonus adjustment discussed above and due to our EOR divestiture. These decreases were partially offset by higher LOE in our STACK play. LOE in our STACK play for the three months March 31, 2018, of $5.9 million increased compared to LOE from January 1 – March 21 and March 22 – March 31, 2017, which totaled $2.6 million, as a result of new wells and increased production underscoring our focus on developing that play. LOE in our STACK play was also higher due to cost inflation, which had an impact on increasing LOE per Boe. Cost inflation in oilfield services continues to occur in conjunction with the industry recovery and has led to markedly higher operating costs for items such as water hauling and disposal.

Production taxes (which include severance and valorem taxes)

	Successor		Predecessor
	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Production taxes (in thousands)	$ 2,677	$ 316	$ 2,417
Production taxes per Boe	$ 1.54	$ 1.39	$ 1.35

Production taxes are approximately flat when comparing the three months March 31, 2018, with the total of the periods from January 1 – March 21 and March 22 – March 31, 2017. Although we experienced a decrease in revenue, we did not see a corresponding decrease in production taxes due to state legislative developments that increased production tax rates for certain wells.

In May and November 2017, the Oklahoma legislature passed bills that would effectively increase production taxes on certain producing wells and units in the state. The legislative change in May 2017, which took effect in July 2017, increased the rate on certain horizontal wells spudded on or prior to July 1, 2015 from 1% to 4%. This was followed by a legislative change in November 2017, which took effect in December 2017, which further increased the rate on the aforementioned horizontal wells from 4% to 7%. In March 2018, the Oklahoma legislature approved a production tax increase which resulted in the rate levied on a well's production for the first three years being raised from 2% to 5%. We estimate the impact of the March 2018 rate hike, which takes effect in July 2018, to result in an increase in production taxes of approximately $1.8 million during the latter half of 2018.

Production taxes on a per Boe basis for the three months ending March 31, 2018, increased compared to the average per Boe rate for the periods from January 1 – March 21 and March 22 – March 31, 2017, as a result of the tax rate increases discussed above.

Depreciation, depletion and amortization ("DD&A")

	Successor		Predecessor
	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
DD&A (in thousands):			
Oil and natural gas properties (1)	$ 18,459	$ 3,155	$ 23,442
Property and equipment	2,647	259	1,473
Total DD&A	$ 21,106	$ 3,414	$ 24,915
DD&A per Boe:			
Oil and natural gas properties (1)	$ 10.63	$ 13.90	$ 13.05
Other fixed assets	$ 1.52	$ 1.14	$ 0.82
Total DD&A per Boe	$ 12.15	$ 15.04	$ 13.87

(1) Includes accretion of asset retirement obligations

We adjust our DD&A rate on oil and natural gas properties each quarter for changes in our estimates of oil and natural gas reserves and costs. The implementation of fresh start accounting upon emergence from bankruptcy whereupon the carrying value of our oil and gas properties and tangible property on our balance sheet was restated to fair value impacts the comparability of DD&A between Successor and Predecessor periods. Comparability of DD&A is also impacted by our EOR asset sale in November 2017, which resulted not only in the divestiture of more than half of our proved reserve volumes at the time but also resulted in the removal of a significant amount of future development costs to develop those assets. Notwithstanding transactions affecting comparability, overall oil and natural gas DD&A for the three months March 31, 2018, of $18.5 million was lower compared to oil and natural gas DD&A from January 1 – March 21 and March 22 – March 31, 2017, which totaled $26.6 million, due to lower production and a lower DD&A rate, with each having an approximately equal impact.

General and administrative expenses ("G&A")

(in thousands)	Successor Three months ended March 31, 2018	Successor Period from March 22, 2017 through March 31, 2017	Predecessor Period from January 1, 2017 through March 21, 2017
G&A and cost reduction initiatives:			
Gross G&A expenses	$ 13,934	$ 7,509	$ 8,117
Capitalized exploration and development costs	(2,427)	(1,765)	(1,274)
Net G&A expenses	11,507	5,744	6,843
Cost reduction initiatives	—	6	629
Net G&A and cost reduction initiatives	$ 11,507	$ 5,750	$ 7,472
Net G&A expense per Boe	$ 6.62	$ 25.30	$ 3.81
Net G&A and cost reduction initiatives per Boe	$ 6.62	$ 25.33	$ 4.16

The comparability of gross G&A expenses between 2018 and 2017 is materially impacted by stock compensation and the timing of our recognition of bonus expense. Stock compensation expense for the three months ended March 31, 2018, was due to requisite service costs under our new Management Incentive Plan which was adopted in August 2017. In contrast, we recorded an immaterial amount of stock compensation expense for the period from January 1 to March 21, 2017, in connection with our previous stock incentive plan, which was subsequently cancelled upon emergence from bankruptcy. Provisions set by the Bankruptcy Court during the pendency of our bankruptcy prevented us from paying bonuses in the ordinary course of business. Pursuant to these provisions, we did not accrue bonuses during 2016 and during the entire pendency of our bankruptcy. Upon emergence, we recognized expense for the entire amount of our 2016 fiscal year bonus (paid in March 2017) and also accrued a pro rata estimate of our 2017 fiscal year bonus through that date. We have accrued bonuses in the ordinary course of business subsequent to our emergence. The transactions affecting comparability are disclosed in the table below:

(in thousands)	Successor Three months ended March 31, 2018	Successor Period from March 22, 2017 through March 31, 2017	Predecessor Period from January 1, 2017 through March 21, 2017
Bonus expense, gross	$ 317	$ 6,581	$ —
Stock compensation, gross	5,580	—	194
	$ 5,897	$ 6,581	$ 194

Other than the impact of the transactions described above, gross G&A expense was lower for the three months ended March 31, 2018 compared to gross G&A from January 1 – March 21 and March 22 – March 31, 2017, due to decreased salaries and benefits as a result of lower headcount and a decrease in professional fees incurred.

Cost reduction initiatives

Cost reduction initiatives during 2017 include expenses related to our efforts to reduce our capital, operating and administrative costs in response to the deterioration of commodity prices. We implemented a workforce reduction in early 2017 and therefore substantially all our expenses for cost reduction initiatives are for one-time severance and termination benefits in connection with the layoffs.

Loss on asset sale

In November 2017, we closed on the sale of our EOR assets for total proceeds of $163.6 million based on preliminary estimates of closing adjustments. In conjunction with this divestiture, we recorded a loss on sale of $25.2 million during the fourth quarter of 2017. As a result of the final closing adjustments on the sale, we recorded an additional loss of $1.1 million during the first quarter of 2018.

Restructuring expense

We incurred exit costs in conjunction with our EOR asset divestiture, which are predominantly comprised of one-time severance and termination benefits for the affected employees. The expense recorded in 2018 of $0.4 million is a result of termination benefits for the final slate of employees terminated as a result of the divestiture.

Subleases

Prior to the sale of our EOR assets in November 2017, we utilized CO_2 compressors that were considered integral to our EOR operations and were leased under six lease agreements from U.S. Bank. In conjunction with the sale, we continued to lease the compressors, but executed sublease agreements with the purchaser of our EOR assets (the "Sublessee"). Minimum payments under the subleases are equal to the original leases and hence we did not record any losses upon initiation of the subleases. Of the original lease agreements, three are classified as capital leases while the remaining three are classified as operating leases. Prior to the asset sale, the capital leases were included in our full cost amortization base and hence subject to amortization on a units-of-production basis, while also incurring interest expense. The payments under our operating leases were previously recorded as "Lease operating expense" in our statement of operations. All the subleases have been classified as operating leases from a lessor's standpoint. Subsequent to the execution of the subleases, all payments received from the Sublessee are reflected as revenues on our statement of operations. Payments we make to U.S. Bank on the original operating leases, which were $0.4 million for the three months ended March 31, 2018, are reflected in "Other" on our statement of operations. With respect to the capital leases, we have reclassified the amount associated with these leases from the full cost amortization base to plant, property and equipment on our balance sheet and are amortizing the asset on a straight line basis prospectively. We will continue incurring interest expense on the capital leases.

Income taxes

We did not record any net deferred tax benefit for the quarter ended March 31, 2018, as any deferred tax asset arising from the benefit is reduced by a valuation allowance as utilization of the loss carryforwards and realization of other deferred tax assets cannot be reasonably assured. Please see "Note 12—Income Taxes" in Item 8. Financial Statement and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2017, which contains additional information about our income taxes.

Other income and expenses

Interest expense. The following table presents interest expense for the periods indicated:

	Successor		Predecessor
(in thousands)	**Three months ended March 31, 2018**	**Period from March 22, 2017 through March 31, 2017**	**Period from January 1, 2017 through March 21, 2017**
New Credit Facility	$ 2,204	$ —	$ —
Exit Revolver	—	213	—
Exit Term Loan including amortization of discount	—	447	—
Prior Credit Facility	—	—	5,193
Bank fees, other interest and amortization of issuance costs	688	44	917
Capitalized interest	(1,521)	(54)	(248)
Total interest expense	$ 1,371	$ 650	$ 5,862
Average borrowings (excluding amounts subject to compromise)	$ 217,435	$ 295,973	$ 470,915

Interest expense for the three months ended March 31, 2018, of $1.4 million was lower than interest expense for the periods from January 1 – March 21 and March 22 – March 31, 2017, which totaled $6.5 million, due to a decrease in interest incurred on outstanding debt coupled with an increase in capitalized interest. Interest incurred on outstanding debt decreased as a result of a lower outstanding debt and lower interest rates in the current period. Our outstanding debt (excluding amounts subject to compromise for which interest was not accrued) for the first quarter of 2017 averaged approximately $451.5 million compared to our average of $217.4 million for the first quarter of 2018. Furthermore, the interest incurred on our Prior Credit Facility in 2017 was at the default rate, which is higher than the interest rate we would normally be charged when not in default. Capitalized interest increased as a result of a larger carrying balance of unevaluated non-producing leasehold which was driven by our 7,000 acre leasehold purchase in early January 2018.

As a result of applying fresh start accounting upon our emergence from bankruptcy, the carrying value of our unevaluated non-producing leasehold was significantly increased to reflect the fair value of our acreage in the STACK. In future periods subsequent to the adoption of fresh start accounting, we have not and will not be capitalizing interest related to the fresh start step-up of the carrying value of unevaluated acreage. Capitalized interest will only be calculated based on the carrying value of actual purchased leasehold.

Reorganization items

Reorganization items reflect, where applicable, expenses, gains and losses incurred that are incremental and a direct result of the reorganization of the business. As a result of our emergence from bankruptcy, we have also recorded gains on the settlement of liabilities subject to compromise and gains from restating our balance sheet to fair values under fresh start accounting. Our reorganization items are presented below (in thousands):

	Successor		Predecessor
	Three months ended March 31, 2018	Period from March 22, 2017 through March 31, 2017	Period from January 1, 2017 through March 21, 2017
Loss (gain) on the settlement of liabilities subject to compromise	$ 48	$ —	$ (372,093)
Fresh start accounting adjustments	—	—	(641,684)
Professional fees	989	620	18,790
Rejection of employment contracts	—	—	4,573
Write off unamortized issuance costs on Prior Credit Facility	—	—	1,687
Total reorganization items	$ 1,037	$ 620	$ (988,727)

"Professional fees" in the table above is comprised of legal fees for continuing work to resolve outstanding bankruptcy claims and fees to the U.S. Bankruptcy Trustee, which we will continue to incur until our bankruptcy case is closed. Professional fees associated with the U.S. Bankruptcy Trustee of $0.6 million for the current quarter were higher than previous periods due to recent legislative changes that impacted the calculation of such fees. We have since consolidated the reporting of cash transactions to the Bankruptcy Court, which are the basis for calculating trustee fees, and therefore expect to reduce such fees to a normal run rate of approximately $0.1 million per quarter.

Liquidity and capital resources

Our internal sources of liquidity include cash flows from operations, receipts from or payments for commodity derivatives and asset divestitures. In 2018, asset divestitures are expected to be a significant source of liquidity. We expect to generate proceeds of $50 million to $60 million from the sale of non-core oil and natural gas properties. Our external sources of liquidity are comprised of outstanding debt and occasional issuances of equity.

We rely on cash flows from operations to fund our capital program which includes exploration and development, leasehold and property acquisitions. Our industry requires that we continuously commit substantial investment to drill and develop our oil and natural gas properties such that production from new wells can offset the natural production decline from existing wells. During the past three years, cash flows from operations have been insufficient to fully fund our capital programs and instead were augmented by derivative receipts, asset sales and debt.

Our cash balance as of March 31, 2018, was $12.2 million and we had borrowing availability under our New Credit Facility of $78.1 million. As of May 7, 2018, our cash balance was approximately $16.6 million with $221.1 million outstanding on our New Credit Facility and borrowing availability of $63.1 million. We continuously monitor our liquidity needs, coordinate our capital expenditure program with our expected cash flows, and evaluate our available alternative sources of liquidity. We believe that we have sufficient liquidity to fund our capital expenditures and day to day operations at a minimum for the next 12 months.

Our cash flows and liquidity are highly dependent on the prices we receive for oil, natural gas and NGLs. Prices we receive are determined by prevailing market conditions, regional and worldwide economic and geopolitical activity, supply versus demand, weather, seasonality and other factors that influence market conditions and often result in significant volatility in commodity prices. In addition to reducing revenue from commodity sales, low prices can adversely affect our liquidity through the impact on the borrowing base under our credit facilities. When commodity prices decline, the price deck approved by our lenders to determine our borrowing base decreases which leads to a reduction in our borrowing base and hence the available amount we can borrow.

We mitigate the impact of volatility in commodity prices, in part through the use of derivative instruments which help stabilize our cash flow. We currently have derivative contracts in place for oil and natural gas production from 2018 through 2021 (see Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Sources and uses of cash

Our net change in cash is summarized as follows:

(in thousands)	Successor: Three months ended March 31, 2018	Successor: Period from March 22, 2017 through March 31, 2017	Predecessor: Period from January 1, 2017 through March 21, 2017
Cash flows provided by (used in) operating activities	$ 10,376	$ (8,401)	$ 14,385
Cash flows used in investing activities	(104,112)	(4,140)	(28,010)
Cash flows provided by (used in) financing activities	78,193	(88)	(127,732)
Net decrease in cash during the period	$ (15,543)	$ (12,629)	$ (141,357)

Our cash flows from operating activities is derived substantially from the production and sale of oil and natural gas. Cash flows from operating activities for the three months ended March 31, 2018, of $10.4 million increased compared to the three months ended March 31, 2017, which included outflows of $8.4 million for Successor period and inflows of $14.4 million for the Predecessor period. The increase was primarily due to lower cash expenditures on professional fees related to our reorganization and lower cash interest paid partially offset by the loss of operating income from our EOR assets which were sold in late 2017 and an increase in receivables.

When available, we use the net cash provided by operations to partially fund our acquisition, exploration and development activities. During the first quarter of 2018, we also relied on borrowings under our New Credit Facility and cash on hand to help fund our capital expenditures.

Our cash flows from investing activities is comprised primarily of cash inflows from asset dispositions and derivative settlement receipts offset by cash outflows for capital expenditures and derivative settlement payments.

Our actual costs incurred, including costs that we have accrued for during the three months ended March 31, 2018, and our budgeted 2018 capital expenditures for oil and natural gas properties are summarized in the table below.

(in thousands)	Three months ended March 31, 2018: STACK	Other	Total	2018 Budget (1)
Acquisitions	$ 65,835	$ —	$ 65,835	94,000
Drilling	33,406	—	33,406	149,000
Enhancements	977	1,555	2,532	9,000
Total	$ 100,218	$ 1,555	$ 101,773	$ 252,000

(1) Budget categories presented include allocations of capitalized interest and general and administrative expenses.

Net cash used in investing activities during the three months ended March 31, 2018, was comprised of cash outflows for capital expenditure of $99.9 million and payments for derivative settlements of $4.2 million. Capital expenditures during the three months ended March 31, 2018, included the closing payment of $54.8 million on our 7,000 acre leasehold purchase in January 2018. Net cash used in investing activities during the Successor period in 2017 was comprised of cash outflows for capital expenditure of $5.8 million and cash inflows from derivative settlement receipts of $1.7 million. Net cash used in investing activities during the Predecessor period in 2017 was comprised of cash outflows for capital expenditure of $31.2 million, cash inflows from derivative settlement receipts of $1.3 million and cash inflows from asset sales of $1.9 million.

Net cash from financing activities during the three months ended March 31, 2018, was comprised of cash inflows of $79.0 million from borrowings partially offset by cash outflows for repayment of debt and capital leases of $0.8 million. We had minimal cash flows from financing activities during the Successor period in 2017. Cash flows from financing activities during the Predecessor period in 2017 is comprised primarily of cash outflows for repayments of debt and capital leases of $445.4 million and payment of $2.4 million in debt issuance costs partially offset by cash inflows of $270.0 million from new borrowings. The large repayments and borrowings of debt reflect the extinguishment of our Prior Credit Facility and establishment of our Exit Credit Facility upon our emergence from bankruptcy.

Indebtedness

Debt consists of the following as of the dates indicated:

(in thousands)	March 31, 2018	December 31, 2017
New Credit Facility	$ 206,100	$ 127,100
Real estate mortgage notes	9,031	9,177
Capital lease obligations	13,699	14,361
Unamortized issuance costs	(5,682)	(5,979)
Total debt, net	$ 223,148	$ 144,659

Credit facilities

The New Credit Facility is a $400,000 facility collateralized by our oil and natural gas properties and is scheduled to mature on December 21, 2022. Availability under our New Credit Facility is subject to a borrowing base based on the value of our oil and natural gas properties and set by the banks semi-annually on May 1 and November 1 of each year. Availability on the New Credit Facility as of March 31, 2018, after taking into account outstanding borrowings and letters of credit on that date, was $78,072.

The New Credit Facility contains financial covenants that require, for each fiscal quarter, we maintain: (1) a Current Ratio (as defined in the New Credit Facility) of no less than 1.00 to 1.00, and (2) a Ratio of Total Debt to EBITDAX (as defined in the New Credit Facility) of no greater than 4.0 to 1.0 calculated on a trailing four-quarter basis. We were in compliance with these financials covenants as of March 31, 2018.

The New Credit Facility contains covenants and events of default customary for oil and natural gas reserve-based lending facilities. Please see "Note 8—Debt" in Item 8 Financial Statements and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2017, for a discussion of the material provisions of our New Credit Facility

Effective May 9, 2018, we entered into the First Amendment to the Tenth Restated Credit Agreement, among the Company and its subsidiaries, as borrowers, certain financial institutions party thereto, as lenders, and JPMorgan Chase Bank, N.A., as administrative agent (the "Amendment"). The Amendment reaffirmed our borrowing base at the same level of $285 million. In addition, the Amendment provided us with: (i) an increase from $150 million to $250 million to the aggregate amount of secured debt allowed, (ii) a waiver on the automatic reduction to the borrowing base calculation for the issuance of up to $300 million in unsecured debt, (iii) the ability to offset the total debt calculation in the financial covenant calculations by up to $50 million of unrestricted cash and cash equivalents whenever we do not have outstanding borrowings on the facility, and (iv) permission to make payments on account of the purchase, redemption, retirement, acquisition, cancellation or termination of our equity of up to $50 million.

Capital leases

During 2013, we entered into lease financing agreements with U.S. Bank for $24.5 million through the sale and subsequent leaseback of existing compressors owned by us. The lease financing obligations were for 84-month terms and with minimum lease payments of $3.2 million annually. As discussed above, these compressors are currently being subleased.

Contractual obligations

We have numerous contractual commitments in the ordinary course of business including debt service requirements, operating leases, capital leases and purchase obligations. Our operating leases include leases relating to office equipment, which have terms of up to five years, and leases on CO_2 recycle compressors, which have terms of seven years. Aside from operating leases, we also have capital leases for our CO_2 recycle compressors. In conjunction with the sale of our EOR assets, all our leased CO_2 compressors were subleased to the buyer of those assets although we remain the primary obligor in relation to U.S. Bank, the originating lessor. The subleases are structured such that the lease payments and remaining lease term are identical to the original leases.

As of March 31, 2018, our purchase obligations included contracts for three drilling rigs. Other than the changes described herein and additional debt borrowings during the quarter, there were no material changes to our contractual commitments since December 31, 2017.

Off-balance sheet arrangements

Our off-balance sheet arrangements as of March 31, 2018, include warrants to purchase 140,023 shares of Successor common stock with an exercise price of $36.78 per share and expiring on June 30, 2018.

Financial position

Although not directly comparable between Successor and Predecessor, we believe that the following discussion of material changes in our balance sheet may be useful:

(in thousands)	March 31, 2018	December 31, 2017	Change
Assets			
Accounts receivable, net	70,495	60,363	10,132
Total oil and natural gas properties	1,076,159	992,353	83,806
Liabilities			
Long-term debt and capital leases	223,148	144,659	78,489
Derivative instruments	25,383	13,126	12,257

- Accounts receivable increased as result of an increase in capital expenditures which increased the amounts due to us by our joint interest owners.
- The increase to oil and natural gas properties was primarily due to our 7,000 acre leasehold acquisition in January 2018, which had a purchase price of $60.6 million, and drilling costs partially offset by depreciation during the period.
- Long-term debt was higher in total due to borrowings under our New Credit Facility, which were primarily utilized for capital expenditures, including leasehold acquisitions.
- Our net liability for derivative instruments increased in magnitude as a result of an increase in forward commodity prices and due to the repricing of derivatives discussed previously.

Non-GAAP financial measure and reconciliation

Management uses Adjusted EBITDA (as defined below) as a supplemental financial measurement to evaluate our operational trends. Items excluded generally represent non-cash adjustments, the timing and amount of which cannot be reasonably estimated and are not considered by management when measuring our overall operating performance. In addition, Adjusted EBITDA is generally consistent with the EBITDAX calculation that is used in the Ratio of Total Debt to EBITDAX covenant under our New Credit Facility. We consider compliance with this covenant to be material.

Adjusted EBITDA is used as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to net income, as an indicator of our operating performance, as an alternative to cash flows from operating activities, or as a measure of liquidity. Adjusted EBITDA is not defined under GAAP and, accordingly, it may not be a comparable measurement to those used by other companies.

We define adjusted EBITDA as net income, adjusted to exclude (1) asset impairments, (2) interest and other financing costs, net of capitalized interest, (3) income taxes, (4) depreciation, depletion and amortization, (5) non-cash change in fair value of non-hedge derivative instruments, (6) interest income, (7) stock-based compensation expense, (8) gain or loss on disposed assets, (9) upfront premiums paid on settled derivative contracts, (10) impairment charges, (11) other significant, unusual non-cash charges, (12) proceeds from any early monetization of derivative contracts with a scheduled maturity date more than 12 months following the date of such monetization—this exclusion is consistent with our prior treatment, for EBITDA reporting, of any large monetization of derivative contracts and (13) certain expenses related to our restructuring, cost reduction initiatives, reorganization and fresh start accounting activities for which our lenders have permitted us to exclude when calculating covenant compliance.

The following tables provide a reconciliation of net (loss) income to adjusted EBITDA for the specified periods:

(in thousands)	Successor: Three months ended March 31, 2018	Successor: Period from March 22, 2017 through March 31, 2017	Predecessor: Period from January 1, 2017 through March 21, 2017
Net (loss) income	$ (11,442)	$ (19,683)	$ 1,041,959
Interest expense	1,371	650	5,862
Income tax expense	—	1	37
Depreciation, depletion, and amortization	21,106	3,414	24,915
Non-cash change in fair value of derivative instruments	12,257	13,807	(46,721)
Impact of derivative repricing	(572)	—	—
Loss (gain) on settlement of liabilities subject to compromise	48	—	(372,093)
Fresh start accounting adjustments	—	—	(641,684)
Interest income	(1)	—	(133)
Stock-based compensation expense	4,623	—	155
Loss on sale of assets	1,044	—	(206)
Write-off of debt issuance costs, discount and premium	—	—	1,687
Restructuring, reorganization and other	989	626	24,297
Adjusted EBITDA	$ 29,423	$ (1,185)	$ 38,075

Our New Credit Facility requires us to maintain a current ratio (as defined in New Credit Facility) of not less than 1.0 to 1.0. The definition of current assets and current liabilities used for determination of the current ratio computed for loan compliance purposes differs from current assets and current liabilities determined in compliance with GAAP. Since compliance with financial covenants is a material requirement under our New Credit Facility, we consider the current ratio calculated under our New Credit Facility to be a useful measure of our liquidity because it includes the funds available to us under our Credit Facility and is not affected by the volatility in working capital caused by changes in the fair value of derivatives. The following table discloses the current ratio for our loan compliance compared to the ratio calculated per GAAP:

(dollars in thousands)	March 31, 2018	December 31, 2017
Current assets per GAAP	$ 93,045	$ 95,894
Plus—Availability under New Credit Facility	78,072	157,072
Current assets as adjusted	$ 171,117	$ 252,966
Current liabilities per GAAP	$ 113,996	$ 117,075
Less—Current derivative instruments	(10,548)	(8,959)
Less—Current asset retirement obligation	(2,749)	(2,774)
Less—Current maturities of long term debt	(3,306)	(3,273)
Current liabilities as adjusted	$ 97,393	$ 102,069
Current ratio per GAAP	0.82	0.82
Current ratio for loan compliance	1.76	2.48

Critical accounting policies

For a discussion of our critical accounting policies, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations ” in our Annual Report on Form 10-K for the year ended December 31, 2017.

Also see the footnote disclosures included in “Note 1—Nature of operations and summary of significant accounting policies” and “Note 5—Revenue recognition” in Item 1. Financial Statements of this report.

Recent accounting pronouncements

See recently adopted and issued accounting standards in “Note 1—Nature of operations and summary of significant accounting policies” in Item 1. Financial Statements of this report.

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

Commodity prices

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of, and demand for, 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. We cannot predict future oil and natural gas prices with any degree of certainty. Sustained declines in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of net oil and natural gas reserves that we can produce economically. Any reduction in reserves, including reductions due to price fluctuations, can reduce our borrowing base under our New Credit Facility and adversely affect our liquidity and our ability to obtain capital for our acquisition, exploration and development activities. Based on our production for the three months ended March 31, 2018, our gross revenues from oil and natural gas sales would change approximately $1.1 million for each $1.00 change in oil and natural gas liquid prices and $0.4 million for each $0.10 change in natural gas prices.

To mitigate a portion of our exposure to fluctuations in commodity prices, we enter into various types of derivative instruments, which in the past have included commodity price swaps, collars, put options, enhanced swaps and basis protection swaps. We do not apply hedge accounting to any of our derivative instruments. As a result, all gains and losses associated with our derivative contracts are recognized immediately as “Derivative (losses) gains” in the consolidated statements of operations. This can have a significant impact on our results of operations due to the volatility of the underlying commodity prices. Please see “Note 6—Derivative instruments” in “Item 1. Financial Statements” of this report for further discussion of our derivative instruments.

Derivative positions are adjusted in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our derivative positions continuously and if future market conditions change, we may execute a cash settlement with our counterparty, restructure the position, or enter into a new swap that effectively reverses the current position (a counter-swap). The factors we consider in closing or restructuring a position before the settlement date are identical to those reviewed when deciding to enter into the original derivative position.

The fair value of our outstanding derivative instruments at March 31, 2018, was a net liability of $25.4 million. Based on our outstanding derivative instruments as of March 31, 2018, summarized below, a 10% increase in the March 31, 2018, forward curves used to mark-to-market our derivative instruments would have increased our net liability position to $60.4 million, while a 10% decrease would have resulted in a net asset position to $7.0 million.

Our outstanding oil derivative instruments as of March 31, 2018, are summarized below:

Period and type of contract	Volume MBbls	Weighted average fixed price per Bbl Swaps	Purchased puts	Sold calls
April - June 2018				
Oil swaps	546	$ 58.00	$ —	$ —
Oil collars	46	$ —	$ 50.00	$ 60.50
July - September 2018				
Oil swaps	515	$ 58.21	$ —	$ —
Oil collars	46	$ —	$ 50.00	$ 60.50
October - December 2018				
Oil swaps	515	$ 58.21	$ —	$ —
Oil collars	46	$ —	$ 50.00	$ 60.50
January - March 2019				
Oil swaps	333	$ 54.26	$ —	$ —
April - June 2019				
Oil swaps	337	$ 54.26	$ —	$ —
July - September 2019				
Oil swaps	321	$ 54.26	$ —	$ —
October - December 2019				
Oil swaps	321	$ 54.26	$ —	$ —
January - March 2020				
Oil swaps	394	$ 49.59	$ —	$ —
April - June 2020				
Oil swaps	357	$ 49.42	$ —	$ —
July - September 2020				
Oil swaps	375	$ 49.46	$ —	$ —
October - December 2020				
Oil swaps	422	$ 49.68	$ —	$ —
January - March 2021				
Oil swaps	134	$ 44.34	$ —	$ —
April - June 2021				
Oil swaps	135	$ 44.34	$ —	$ —
July - September 2021				
Oil swaps	136	$ 44.34	$ —	$ —
October - December 2021				
Oil swaps	138	$ 44.34	$ —	$ —

Our outstanding natural gas derivative instruments as of March 31, 2018, are summarized below:

Period and type of contract	Volume BBtu		Weighted average fixed price per MMBtu
April - June 2018			
Natural gas swaps	2,783	$	2.86
July - September 2018			
Natural gas swaps	2,609	$	2.87
October - December 2018			
Natural gas swaps	2,519	$	2.88
January - March 2019			
Natural gas swaps	1,889	$	2.80
April - June 2019			
Natural gas swaps	1,878	$	2.80
July - September 2019			
Natural gas swaps	1,838	$	2.81
October - December 2019			
Natural gas swaps	2,027	$	2.81
January - March 2020			
Natural gas swaps	900	$	2.77
April - June 2020			
Natural gas swaps	900	$	2.77
July - September 2020			
Natural gas swaps	900	$	2.77
October - December 2020			
Natural gas swaps	900	$	2.77

Interest rates. All of the outstanding borrowings under our New Credit Facility as of March 31, 2018, are subject to market rates of interest as determined from time to time by the banks. As of March 31, 2018, borrowings bear interest at the Adjusted LIBO Rate, as defined under the New Credit Facility, plus the applicable margin, which resulted in a weighted average interest rate of 4.86% on the amount outstanding. Any increases in these rates can have an adverse impact on our results of operations and cash flow. Assuming a constant debt level under our New Credit Facility of $285.0 million, equal to our borrowing base at March 31, 2018, the cash flow impact for a 12-month period resulting from a 100 basis point change in interest rates would be $2.9 million.

ITEM 4. *CONTROLS AND PROCEDURES*

Disclosure Controls and procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of March 31, 2018, at the reasonable assurance level**.**

Changes in Internal control over financial reporting

There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting except for the implementation of changes in our internal controls to ensure we adequately evaluate our contracts and properly assess the impact of the new accounting standard related to revenue recognition on our financial statements which was adopted on January 1, 2018.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Please see "Note 10—Commitments and contingencies" in Item 1. Financial Statements of this report for a discussion of our material legal proceedings. In our opinion, there are no other material pending legal proceedings to which we are a party or of which any of our property is the subject. However, due to the nature of our business, certain legal or administrative proceedings may arise from time to time in the ordinary course of business. While the outcome of these legal matters cannot be predicted with certainty, we do not expect them to have a material adverse effect on our financial condition, results of operations or cash flows.

ITEM 1A. RISK FACTORS

During the first quarter of 2018, there have been no material changes in our risk factors from what we disclosed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2017.

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

The following table provides information regarding Class A common stock repurchases made by the Company during the three months ended March 31, 2018.

Period	Total number of shares purchased (1)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
January 1 - January 31, 2018	—	$ —	N/A	N/A
February 1 - February 28, 2018	—	$ —	N/A	N/A
March 1 - March 31, 2018	63,919	$ 22.25	N/A	N/A
Total	63,919	$ 22.25	N/A	N/A

(1) All shares purchased represent shares surrendered by the MIP participants to cover tax liabilities.

ITEM 5. OTHER INFORMATION

On May 9, 2018, we entered into the First Amendment (the "Amendment") to our New Credit Facility, among the Company and its subsidiaries, as borrowers, certain financial institutions party thereto, as lenders, and JPMorgan Chase Bank, N.A., as administrative agent. The Amendment reaffirmed our borrowing base at the same level of $285,000,000. In addition, the Amendment, among other things, provided us with: (i) an increase from $150,000,000 to $250,000,000 to the aggregate amount of secured debt allowed; (ii) a waiver on the automatic reduction to the borrowing base calculation for the issuance of up to $300,000,000 in unsecured debt; (iii) the ability to offset the total debt calculation in the financial covenant calculations by up to $50,000,000 of unrestricted cash and cash equivalents whenever we do not have outstanding borrowings on the facility; and (iv) permission to make payments on account of the purchase, redemption, retirement, acquisition, cancellation or termination of our equity of up to $50,000,000.

Certain of the lenders under the New Credit Facility have in the past performed, and may in the future from time to time perform, investment banking, financial advisory, lending or commercial banking services for the Company and its subsidiaries, for which they have received, and may in the future receive, customary compensation and reimbursement of expenses.

The foregoing summary of the Amendment is not complete and is qualified by reference to the full text of the Amendment filed as Exhibit 10.1 hereto and incorporated by reference herein.

ITEM 6. EXHIBITS

Exhibit No.	Description
2.1**	First Amendment to Purchase and Sale Agreement dated January 2, 2018, by and among Blake Production Company, Inc., Fairway Energy L.L.C., Vernon Resources LLC, ABV Ventures LLC and Chaparral Energy, L.L.C. (Incorporated by reference to Exhibit 2.4 of the Company's Annual Report on Form 10-K filed on March 29, 2018).
3.1*	Third Amended and Restated Certificate of Incorporation of Chaparral Energy, Inc., dated as of March 21, 2017 (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K filed on March 27, 2017).
3.2*	Amended and Restated Bylaws of Chaparral Energy, Inc., dated as of March 21, 2017 (Incorporated by reference to Exhibit 3.2 of the Company's Current Report on Form 8-K filed on March 27, 2017).
4.1*	Registration Rights Agreement, dated as of March 21, 2017, by and among Chaparral Energy, Inc. and the Stockholders named therein (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed on March 27, 2017).

Exhibit No.	Description
4.2*	Warrant Agreement dated as of March 21, 2017, among Chaparral Energy, Inc. and Computershare Inc. as warrant agent (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K filed on March 27, 2017).
4.3*	Stockholders Agreement, dated as of March 21, 2017, by and among Chaparral Energy, Inc. and the Stockholders named therein (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K filed on March 27, 2017).
4.4*	First Amendment to Stockholders Agreement, dated as of March 6, 2018, by and among Chaparral Energy, Inc. and the Stockholders named therein (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K filed on March 9, 2018).
10.1	First Amendment to Tenth Restated Credit Amendment, effective as of May 9, 2018, by and among Chaparral Energy, Inc., a Delaware corporation, each Guarantor party hereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and each of the Lenders party hereto.
31.1	Certification by Principal Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act.
31.2	Certification by Principal Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act.
32.1	Certification by Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification by Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Incorporated by reference

** The schedules and exhibits to this agreement have been omitted from this filing pursuant to Item 601(b)(2) of Regulation S-K. Chaparral Energy, Inc. will furnish copies of such schedules to the Securities and Exchange Commission upon request.

SIGNATURES

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

CHAPARRAL ENERGY, INC.

By:	/s/ K. Earl Reynolds
Name:	K. Earl Reynolds
Title:	*Chief Executive Officer* (Principal Executive Officer)

By:	/s/ Joseph O. Evans
Name:	Joseph O. Evans
Title:	*Chief Financial Officer and Executive Vice President* (Principal Financial Officer and Principal Accounting Officer)

Date: May 10, 2018

Exhibit 10.1

FIRST AMENDMENT TO TENTH RESTATED CREDIT AGREEMENT

This First Amendment to Tenth Restated Credit Agreement (this "First Amendment"), effective as of May 9, 2018 (the "First Amendment Effective Date"), is by and among **CHAPARRAL ENERGY, INC.**, a Delaware corporation (the "Borrower"), each Guarantor party hereto (the "Guarantors"), **JPMORGAN CHASE BANK, N.A.**, a national banking association, as Administrative Agent ("Administrative Agent"), and each of the Lenders party hereto.

W I T N E S S E T H:

WHEREAS, the Borrower, Administrative Agent, the other Agents party thereto, Issuing Bank, and the Lenders are parties to that certain Tenth Restated Credit Agreement dated as of December 21, 2017 (as amended prior to the date hereof, the "Credit Agreement") (unless otherwise defined herein, all terms used herein with their initial letter capitalized shall have the meanings given such terms in the Credit Agreement);

WHEREAS, pursuant to the Credit Agreement, the Lenders have made Loans to the Borrower; and

WHEREAS, the parties hereto desire to enter into this First Amendment to (i) amend certain terms of the Credit Agreement as more specifically set forth herein and (ii) evidence the reaffirmation of the Borrowing Base at $285,000,000, in each case, to be effective on the First Amendment Effective Date.

NOW THEREFORE, for and in consideration of the mutual covenants and agreements herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged and confessed, the Borrower, Guarantors, Administrative Agent and the Lenders party hereto hereby agree as follows:

SECTION 1. Amendments. In reliance on the representations, warranties, covenants and agreements contained in this First Amendment, and subject to the satisfaction of the conditions precedent set forth in Section 3 hereof, the Credit Agreement is hereby amended effective as of the First Amendment Effective Date in the manner provided in this Section 1.

1.1 Amended and Restated Definitions. The following definitions in Section 1.02 of the Credit Agreement are hereby amended and restated in their respective entireties to read in full as follows:

"Loan Documents" means this Agreement, the First Amendment, the Notes, the Letter of Credit Agreements, the Letters of Credit, the Engagement Letters and the Security Instruments.

"Total Debt" means, at any date, all Debt of the Borrower and the Consolidated Restricted Subsidiaries on a consolidated basis, (a) excluding (i) non-cash obligations under ASC 815, (ii) accounts payable and other accrued liabilities (for the deferred purchase price of Property or services) from time to time incurred in the ordinary course of business which are not greater than ninety

(90) days past the date of receipt of the invoice or delinquent or which are being contested in good faith by appropriate action and for which adequate reserves have been maintained in accordance with GAAP, (iii) Debt with respect to letters of credit to the extent such letters of credit have not been drawn, (iv) obligations with respect to surety or performance bonds and similar instruments entered into in the ordinary course of business in connection with the operation of Oil and Gas Properties, and (v) Debt of the type described in clauses (f), (g), (h), (i), (j), (k) and (m) of the definition of "Debt", and (b) less, so long as there are no Loans outstanding on such date, the lesser of (i) the unrestricted cash and cash equivalents of the Borrower and its Restricted Subsidiaries on such date and (ii) $50,000,000.

1.2 Additional Definitions. Section 1.02 of the Credit Agreement is hereby amended to add the following definitions to such Section in appropriate alphabetical order:

"First Amendment" means that certain First Amendment to Tenth Restated Credit Agreement dated effective as of May 9, 2018, among the Borrower, the Guarantors party thereto, the Administrative Agent and the Lenders party thereto.

"First Amendment Effective Date" means May 9, 2018.

"Maximum Junior Lien Debt Amount" means $250,000,000; *provided*, that if either (a) the Borrower issues or incurs any unsecured Permitted Senior Additional Debt on or after the First Amendment Effective Date but prior to the date that the Borrower issues or incurs any secured Permitted Senior Additional Debt or (b) the Borrower has not issued or incurred any secured Permitted Senior Additional Debt on or prior to October 31, 2018, then the "Maximum Junior Lien Debt Amount" shall automatically be reduced to $150,000,000 on the earlier of (i) the date on which the Borrower issues or incurs such unsecured Permitted Senior Additional Debt described in the foregoing clause (a) of this definition and (ii) November 1, 2018.

1.3 Amendment to Section 2.07(e) of the Credit Agreement. Section 2.07(e) of the Credit Agreement is hereby amended and restated in its entirety to read in full as follows:

"(e) Automatic Reduction of Borrowing Base – Issuance of Permitted Senior Additional Debt. Subject to the last sentence of this Section 2.07(e), upon any issuance or incurrence of Permitted Senior Additional Debt (other than Permitted Senior Additional Debt that refinances or replaces then existing Permitted Senior Additional Debt, up to the principal amount of such then existing Permitted Senior Additional Debt that is refinanced or replaced), the Borrowing Base shall automatically be decreased by an amount equal to 25% of the aggregate notional principal amount of such Permitted Senior Additional Debt issued or incurred at such time. Such decrease in the Borrowing Base shall occur automatically upon the issuance or incurrence of such Permitted Senior Additional Debt on the date of issuance or incurrence, without any vote of the

Lenders or action by the Administrative Agent. Upon any such reduction in the Borrowing Base, the Administrative Agent shall promptly deliver a New Borrowing Base Notice to the Borrower and the Lenders. Notwithstanding anything herein to the contrary, there shall be no such reduction of the Borrowing Base in connection with the first $300,000,000 of unsecured Permitted Senior Additional Debt issued or incurred by the Borrower on or after the First Amendment Effective Date, so long as (i) any such issuance or incurrence occurs on or prior to October 31, 2018 and (ii) the Borrower has not issued or incurred any secured Permitted Senior Additional Debt prior to the issuance or incurrence of such unsecured Permitted Senior Additional Debt."

1.4 Debt Covenant.

(a) Section 9.02(h), Section 9.02(k) and Section 9.03(e) of the Credit Agreement are each hereby amended by deleting the reference to "$150,000,000" contained in each such Section and inserting in lieu thereof in each instance a reference to "the Maximum Junior Lien Debt Amount".

(b) Section 9.02(h) of the Credit Agreement is hereby amended by adding the following proviso immediately prior to the period at the end of such Section 9.02(h), which shall read in full as follows:

; and *provided further*, that the aggregate principal amount of Debt permitted to be incurred or issued under this Section 9.02(h) during the period commencing on the First Amendment Effective Date and ending on October 31, 2018 shall not exceed $350,000,000

1.5 Restricted Payments. Section 9.04(a) of the Credit Agreement is hereby amended by replacing the word "and" at the end of clause (ii) thereof with a comma and by adding a new clause (iv) thereto immediately following clause (iii) thereof, which clause (iv) shall read in full as follows:

", and (iv) the Borrower may make payments on account of the purchase, redemption, retirement, acquisition, cancellation or termination of its Equity Interests in an amount not to exceed $50,000,000 in the aggregate for all such payments during the term of this Agreement; *provided* that in the case of this clause (iv), (x) no Default shall exist at the time of such payment or result therefrom, (y) the Borrowing Base Utilization Percentage shall not exceed eighty percent (80%) immediately after giving effect to such payment (and any Borrowings made in connection therewith) and (z) immediately after giving effect to such payment (and any Borrowings made in connection therewith), the ratio of Total Debt as of the date of such payment to EBITDAX for the most recently ended four-fiscal quarter period for which financial statements are available does not exceed 3.00 to 1.00."

SECTION 2. Borrowing Base. In reliance on the covenants and agreements contained in this First Amendment, and subject to the satisfaction of the conditions precedent set forth in

Section 3 hereof, Administrative Agent and the Required Lenders agree that the Borrowing Base shall be and hereby is reaffirmed at $285,000,000, effective as of the First Amendment Effective Date and continuing until the next Scheduled Redetermination, Interim Redetermination or other redetermination or adjustment of the Borrowing Base thereafter. The Borrower, the Administrative Agent, and the Lenders acknowledge that the reaffirmation of the Borrowing Base provided for in this Section 2 constitutes the Scheduled Redetermination intended to be effective on, or as promptly as reasonably practicable after, May 1, 2018, as referenced in Section 2.07(b) of the Credit Agreement, and that this First Amendment constitutes the New Borrowing Base Notice with respect to such Scheduled Redetermination.

SECTION 3. Conditions Precedent to this First Amendment. The effectiveness of this First Amendment is subject to the satisfaction or waiver of each of the following conditions precedent:

3.1 Counterparts. Administrative Agent shall have received counterparts hereof duly executed by the Borrower, each Guarantor and Lenders constituting Required Lenders.

3.2 Fees and Expenses. Administrative Agent shall have received all fees and other amounts due and payable on or prior to the First Amendment Effective Date in accordance with Section 12.03 of the Credit Agreement and Section 5.3 hereof.

3.3 Amendment Fees. Administrative Agent shall have received a non-refundable amendment fee for the benefit of each of the Lenders executing and delivering this First Amendment in an aggregate amount for each such Lender equal to 5 basis points (.05%) of the amount of such Lender's Revolving Credit Commitment as of the First Amendment Effective Date (after giving effect to Section 2 hereof).

3.4 Other Documents. Administrative Agent shall have been provided with such other documents, instruments and agreements, and the Borrower shall have taken such actions, as Administrative Agent or counsel to Administrative Agent may reasonably require in connection with this First Amendment and the transactions contemplated hereby.

SECTION 4. Representations and Warranties of the Credit Parties. To induce the Lenders and Administrative Agent to enter into this First Amendment, each Credit Party hereby represents and warrants to the Lenders and Administrative Agent as follows:

4.1 Reaffirm Existing Representations and Warranties. Each representation and warranty of each Credit Party contained in the Credit Agreement and the other Loan Documents is true and correct in all material respects on the date hereof and will be true and correct in all material respects after giving effect to the amendments set forth in Section 1 hereof, except to the extent that (a) any such representation and warranty is expressly limited to an earlier date, in which case such representation and warranty is and will be true and correct in all material respects as of such specified earlier date and (b) any such representation and warranty is expressly qualified by materiality or by reference to Material Adverse Effect, in which case such representation and warranty (as so qualified) is and will be true and correct in all respects.

4.2 Due Authorization. The execution, delivery and performance by each Credit Party that is a party hereto of this First Amendment are within such Credit Party's corporate, limited liability company, or partnership powers (as applicable) and have been duly authorized by all necessary corporate, limited liability company, or partnership action (as applicable).

4.3 Validity and Enforceability. This First Amendment constitutes the valid and binding obligation of each Credit Party that is a party hereto, enforceable against such Credit Party in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting creditors' rights generally and subject to general principles of equity, regardless of whether considered in a proceeding in equity or at law.

4.4 No Default, Event of Default or Borrowing Base Deficiency. No Default, Event of Default or Borrowing Base Deficiency has occurred and is continuing.

SECTION 5. Miscellaneous.

5.1 Reaffirmation of Loan Documents and Liens. Any and all of the terms and provisions of the Credit Agreement and the other Loan Documents shall, except as amended or otherwise modified hereby, remain in full force and effect. Except to the extent expressly set forth herein, the amendments contemplated hereby shall not limit or impair any Liens securing the Indebtedness, each of which are hereby ratified and affirmed to secure the Indebtedness as such Indebtedness may be increased or otherwise affected by this First Amendment.

5.2 Parties in Interest. All of the terms and provisions of this First Amendment shall bind and inure to the benefit of the parties hereto and their respective successors and permitted assigns.

5.3 Legal Expenses. The Borrower hereby agrees to pay, as and when required by Section 12.03 of the Credit Agreement, all reasonable and documented out-of-pocket fees and expenses of counsel to Administrative Agent incurred by Administrative Agent in connection with the preparation, negotiation and execution of this First Amendment and all related documents.

5.4 Counterparts. This First Amendment may be executed in counterparts (and by the different parties hereto on different counterparts), each of which shall constitute an original, but all of which when taken together shall constitute a single contract. Delivery of an executed counterpart of a signature page of this First Amendment by fax or other electronic transmission (e.g., .pdf) shall be effective as delivery of a manually executed counterpart of this First Amendment.

5.5 Complete Agreement. THIS FIRST AMENDMENT, THE CREDIT AGREEMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT AMONG THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN OR AMONG THE PARTIES.

5.6 Headings. The headings, captions and arrangements used in this First Amendment are, unless specified otherwise, for convenience only and shall not be deemed to limit, amplify or modify the terms of this First Amendment, nor affect the meaning thereof.

5.7 Effectiveness. This First Amendment shall be effective automatically and without necessity of any further action by the Borrower, Administrative Agent or Lenders when counterparts hereof have been executed by the Borrower, each Guarantor, Administrative Agent and Lenders constituting Required Lenders, and all conditions to the effectiveness hereof set forth herein have been satisfied. Administrative Agent shall notify the Borrower and the Lenders of the effectiveness of this Amendment, and such notice shall be conclusive and binding.

5.8 Governing Law. This First Amendment shall be governed by, and construed in accordance with, the laws of the State of New York.

[Signature pages follow]

IN WITNESS WHEREOF, the parties hereto have caused this First Amendment to be duly executed as of the day and year first above written.

BORROWER:

CHAPARRAL ENERGY, INC., a Delaware corporation

By: /s/ JOSEPH O. EVANS
Name: Joseph O. Evans
Title: Executive Vice President and Chief Financial Officer

GUARANTORS:

CHAPARRAL ENERGY, L.L.C., an Oklahoma limited liability company

CHAPARRAL RESOURCES, L.L.C., an Oklahoma limited liability company

CHAPARRAL CO_2, L.L.C., an Oklahoma limited liability company

CEI ACQUISITION, L.L.C., a Delaware limited liability company

CEI PIPELINE, L.L.C., a Texas limited liability company

CHAPARRAL REAL ESTATE, L.L.C., an Oklahoma limited liability company

GREEN COUNTRY SUPPLY, INC., an Oklahoma corporation

CHAPARRAL EXPLORATION, L.L.C., a Delaware limited liability company

ROADRUNNER DRILLING, L.L.C., an Oklahoma limited liability company

CHAPARRAL BIOFUELS, L.L.C., an Oklahoma limited liability company

By: /s/ JOSEPH O. EVANS
Name: Joseph O. Evans
Title: Executive Vice President and Chief Financial Officer

ADMINISTRATIVE AGENT/LENDER:

JPMORGAN CHASE BANK, N.A.,
as Administrative Agent and a Lender

By: /s/ ORLANDO CASTANEDA
Name: Orlando Castaneda
Title: Authorized Officer

LENDER:

CAPITAL ONE, NATIONAL ASSOCIATION

By: /s/ CAMERON BREITENBACH
Name: Cameron Breitenbach
Title: Vice President

LENDER: **NATIXIS, NEW YORK BRANCH**

By: /s/ BRICE LE FOYER
Name: Brice Le Foyer
Title: Executive Director

By: /s/ VIKRAM NATH
Name: Vikram Nath
Title: Director

LENDER: **KEYBANK NATIONAL ASSOCIATION**

By: /s/ DAVID BORNSTEIN
Name: David Bornstein
Title: Senior Vice President

Signature Page
First Amendment to Tenth Restated Credit Agreement
Chaparral Energy, Inc.

LENDER: **SOCIÉTÉ GÉNÉRALE**

By: /s/ MAX SONNONSTINE
Name: Max Sonnonstine
Title: Director

LENDER:		**ABN AMRO CAPITAL USA LLC**
	By:	/s/ DARRELL HOLLEY
	Name:	Darrell Holley
	Title:	Managing Director
	By:	/s/ SCOTT MYATT
	Name:	Scott Myatt
	Title:	Executive Director

LENDER:

CANADIAN IMPERIAL BANK OF COMMERCE, NEW YORK BRANCH

By: /s/ TRUDY NELSON
Name: Trudy Nelson
Title: Authorized Signatory

By: /s/ MEGAN LARSON
Name: Megan Larson
Title: Authorized Signatory

LENDER: **COMPASS BANK**

By: /s/ MARK H. WOLF
Name: Mark H. Wolf
Title: Senior Vice President

Signature Page
First Amendment to Tenth Restated Credit Agreement
Chaparral Energy, Inc.

LENDER:

CREDIT AGRICOLE CORPORATE AND INVESTMENT BANK

By: /s/ MICHAEL WILLIS
Name: Michael Willis
Title: Managing Director

By: /s/ DIXON SCHULTZ
Name: Dixon Schultz
Title: Managing Director

LENDER: **DEUTSCHE BANK AG NEW YORK BRANCH**

By: /s/ MARGUERITE SUTTON
Name: Marguerite Sutton
Title: Vice President

By: /s/ ALICIA SCHUG
Name: Alicia Schug
Title: Vice President

LENDER: **FIFTH THIRD BANK**

By: /s/ JUSTIN BELLAMY
Name: Justin Bellamy
Title: Director

LENDER:

THE HUNTINGTON NATIONAL BANK

By: /s/ MARGARET NIEKRASH
Name: Margaret Niekrash
Title: Senior Vice President

LENDER: **THE TORONTO-DOMINION BANK, NEW YORK BRANCH**

By: /s/ ANNIE DORVAL
Name: Annie Dorval
Title: Authorized Signatory

LENDER: **ASSOCIATED BANK, N.A.**

By: /s/ FARHAN IQBAL
Name: Farhan Iqbal
Title: Senior Vice President

LENDER: **BANK OF AMERICA, N.A.**

By: /s/ RAZA JAFFERI
Name: Raza Jafferi
Title: Director

LENDER: **COMERICA BANK**

By: /s/ CASSANDRA M. LUCAS
Name: Cassandra M. Lucas
Title: Portfolio Manager

LENDER: **EAST WEST BANK**

By: /s/ REED THOMPSON
Name: Reed Thompson
Title: Senior Vice President

Signature Page
First Amendment to Tenth Restated Credit Agreement
Chaparral Energy, Inc.

Exhibit 31.1

CERTIFICATION

I, K. Earl Reynolds, Chief Executive Officer of Chaparral Energy, Inc., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Chaparral Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;
   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 10, 2018

/s/ K. Earl Reynolds

K. Earl Reynolds
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Joseph O. Evans, Chief Financial Officer of Chaparral Energy, Inc., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Chaparral Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;
   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 10, 2018

/s/ Joseph O. Evans

Joseph O. Evans
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PERIODIC REPORT

I, K. Earl Reynolds, Chief Executive Officer of Chaparral Energy Inc. (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the period ended March 31, 2018 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: May 10, 2018

/s/ K. Earl Reynolds

K. Earl Reynolds
Chief Executive Officer

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

Exhibit 32.2

CERTIFICATION OF PERIODIC REPORT

I, Joseph O. Evans, Chief Financial Officer of Chaparral Energy Inc. (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the year ended March 31, 2018 (the “Report”) fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: May 10, 2018

/s/ Joseph O. Evans
Joseph O. Evans
Chief Financial Officer

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