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 September 30, 2018
OR

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

For the transition period from ______ to ______
Commission file number: 001-38602

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

Delaware	**73-1590941**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
701 Cedar Lake Boulevard Oklahoma City, Oklahoma	**73114**
(Address of principal executive offices)	**(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, if any, every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer			☒
Smaller reporting company			☐
Emerging growth company			☐

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

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the 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 November 9, 2018:

Class	**Number of Shares**
Class A Common Stock, $0.01 par value	38,585,291
Class B Common Stock, $0.01 par value	7,871,512

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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;
- covenant compliance under instruments governing any of our existing or future indebtedness;
- 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;

- the outcome, timing or effects of 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 recycled 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.
Natural gas liquids (NGLs)	Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, 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.
Prior 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.
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	Our 8.75% senior notes due 2023.
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)	September 30, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 48,960	$ 27,732
Accounts receivable, net	65,780	60,363
Inventories, net	5,774	5,138
Prepaid expenses	2,312	2,661
Total current assets	122,826	95,894
Property and equipment, net	43,996	50,641
Oil and natural gas properties, using the full cost method:		
Proved	771,028	634,294
Unevaluated (excluded from the amortization base)	558,081	482,239
Accumulated depreciation, depletion, amortization and impairment	(179,540)	(124,180)
Total oil and natural gas properties	1,149,569	992,353
Other assets	446	418
Total assets	$ 1,316,837	$ 1,139,306
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 66,614	$ 75,414
Accrued payroll and benefits payable	8,315	11,276
Accrued interest payable	7,057	187
Revenue distribution payable	28,470	17,966
Long-term debt and capital leases, classified as current	3,444	3,273
Derivative instruments	29,905	8,959
Total current liabilities	143,805	117,075
Long-term debt and capital leases, less current maturities	305,760	141,386
Derivative instruments	39,042	4,167
Deferred compensation	453	696
Asset retirement obligations	24,358	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; 38,845,797 issued and 38,588,902 outstanding at September 30, 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 September 30, 2018 and December 31, 2017	79	79
Additional paid in capital	972,229	961,200
Treasury stock, at cost, 256,895 and nil shares as of September 30, 2018 and December 31, 2017	(4,872)	—
Accumulated deficit	(164,405)	(118,902)
Total stockholders' equity	803,419	842,766
Total liabilities and stockholders' equity	$ 1,316,837	$ 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)

	Successor				Predecessor
(in thousands, except share and per share data)	**Three months ended September 30, 2018**	**Three months ended September 30, 2017**	**Nine months ended September 30, 2018**	**Period from March 22, 2017 through September 30, 2017**	**Period from January 1, 2017 through March 21, 2017**
Revenues:					
Net commodity sales	65,519	75,947	181,835	157,803	66,531
Sublease revenue	1,199	—	3,595	—	—
Total revenues	66,718	75,947	185,430	157,803	66,531
Costs and expenses:					
Lease operating	12,493	24,209	42,045	51,527	19,941
Transportation and processing (1)	—	2,942	—	6,370	2,034
Production taxes	4,028	4,536	9,473	8,235	2,417
Depreciation, depletion and amortization	22,252	32,167	63,765	66,432	24,915
General and administrative	9,021	9,924	28,718	24,641	6,843
Cost reduction initiatives	210	34	1,034	155	629
Other	402	—	1,633	—	—
Total costs and expenses	48,406	73,812	146,668	157,360	56,779
Operating income	18,312	2,135	38,762	443	9,752
Non-operating (expense) income:					
Interest expense	(4,205)	(5,283)	(7,315)	(10,984)	(5,862)
Derivative (losses) gains	(23,677)	(15,448)	(72,464)	(4,089)	48,006
(Loss) gain on sale of assets	(2,024)	(13)	(2,599)	(876)	206
Other income, net	19	389	123	696	1,167
Net non-operating (expense) income	(29,887)	(20,355)	(82,255)	(15,253)	43,517
Reorganization items, net	(493)	(858)	(2,010)	(2,548)	988,727
(Loss) income before income taxes	(12,068)	(19,078)	(45,503)	(17,358)	1,041,996
Income tax expense	—	37	—	75	37
Net (loss) income	$ (12,068)	$ (19,115)	$ (45,503)	$ (17,433)	$ 1,041,959
Earnings per share:					
Basic for Class A and Class B	(0.27)	(0.42)	(1.01)	(0.39)	*
Diluted for Class A and Class B	(0.27)	(0.42)	(1.01)	(0.39)	*
Weighted average shares used to compute earnings per share:					
Basic for Class A and Class B	45,333,745	44,982,142	45,272,595	44,982,142	*
Diluted for Class A and Class B	45,333,745	44,982,142	45,272,595	44,982,142	*

(1) See “Note 5—Revenue recognition.”
* 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 Statement of Stockholders' Equity
(Unaudited)

(dollars in thousands)	Common stock Shares outstanding	Common stock Amount	Additional paid in capital	Treasury stock	Accumulated deficit	Total
As at December 31, 2017	46,827,762	$ 468	$ 961,200	$ —	$ (118,902)	$ 842,766
Stock-based compensation	55,000	—	11,029	—	—	11,029
Restricted stock forfeited	(165,453)	(1)	—	—	—	(1)
Repurchase of common stock	(256,895)	—	—	(4,872)	—	(4,872)
Net loss	—	—	—	—	(45,503)	(45,503)
Balance at September 30, 2018	46,460,414	$ 467	$ 972,229	$ (4,872)	$ (164,405)	$ 803,419

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

Chaparral Energy, Inc. and subsidiaries
Consolidated Statements of Cash Flows
(Unaudited)

	Successor		Predecessor
	Nine months ended	Period from March 22, 2017 through	Period from January 1, 2017 through
(in thousands)	**September 30, 2018**	**September 30, 2017**	**March 21, 2017**
Cash flows from operating activities			
Net (loss) income	$ (45,503)	$ (17,433)	$ 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	63,765	66,432	24,915
Derivative losses (gains)	72,464	4,089	(48,006)
Loss (gain) on sale of assets	2,599	876	(206)
Other	4,376	1,300	645
Change in assets and liabilities			
Accounts receivable	(6,743)	(16,082)	198
Inventories	(1,415)	2,683	466
Prepaid expenses and other assets	322	2,560	(497)
Accounts payable and accrued liabilities	(12,383)	(13,369)	8,733
Revenue distribution payable	10,895	4,549	(1,875)
Deferred compensation	7,890	2,565	143
Net cash provided by operating activities	96,267	38,170	14,385
Cash flows from investing activities			
Expenditures for property, plant, and equipment and oil and natural gas properties	(252,731)	(114,358)	(31,179)
Proceeds from asset dispositions	36,335	7,791	1,884
(Payments) proceeds from derivative instruments, net	(16,642)	15,143	1,285
Cash in escrow	—	42	—
Net cash used in investing activities	(233,038)	(91,382)	(28,010)
Cash flows from financing activities			
Proceeds from long-term debt	116,000	33,000	270,000
Repayment of long-term debt	(243,554)	(1,154)	(444,785)
Proceeds from Senior Notes	300,000	—	—
Proceeds from rights offering, net	—	—	50,031
Principal payments under capital lease obligations	(2,003)	(1,362)	(568)
Payment of debt issuance costs and other financing fees	(7,572)	—	—
Treasury stock purchased	(4,872)	—	(2,410)
Net cash provided by (used in) financing activities	157,999	30,484	(127,732)
Net increase (decrease) in cash, cash equivalents, and restricted cash	21,228	(22,728)	(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	$ 48,960	$ 22,395	$ 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 canceled and we issued new common stock to the previous holders of our Prior 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 September 30, 2018 (Successor), for the three and nine months ended September 30, 2018 (Successor), the periods of March 22, 2017, through September 30, 2017 (Successor), and the three months ended September 30, 2017 (Successor), is unaudited. The financial information as of December 31, 2017 (Successor), and the period of January 1, 2017, through March 21, 2017 (Predecessor), have 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 and nine months ended September 30, 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 September 30, 2018, cash with a recorded balance totaling approximately $46,640 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.

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:

(dollars in thousands, except per share amounts)

	September 30, 2018	December 31, 2017
Joint interests	$ 28,867	$ 29,032
Accrued commodity sales	34,381	26,516
Derivative settlements	—	157
Other	3,338	5,326
Allowance for doubtful accounts	(806)	(668)
	$ 65,780	$ 60,363

Inventories

Inventories consisted of the following:

	September 30, 2018	December 31, 2017
Equipment inventory	$ 5,282	$ 4,163
Commodities	671	1,154
Inventory valuation allowance	(179)	(179)
	$ 5,774	$ 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 on the Effective Date, 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:

	September 30, 2018	December 31, 2017
Leasehold acreage	$ 532,531	$ 466,711
Capitalized interest	9,289	2,134
Wells and facilities in progress of completion	16,261	13,394
Total unevaluated oil and natural gas properties excluded from amortization	$ 558,081	$ 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 September 30, 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 September 30, 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.

Upon final determination of tax return amounts for the year ended December 31, 2017, we completed the accounting with regard to Section 162(m) provisions under the Act and recorded an immaterial discrete income tax benefit for the nine months ended September 30, 2018, fully offset by a corresponding increase in valuation allowance.

Despite the Company's net loss for the nine months ended September 30, 2018, we did not record any net deferred tax benefit, 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 September 30, 2018, or December 31, 2017.

Elements of the Reorganization Plan provided that our indebtedness related to Prior 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 amount of CODI was $60,398, which reduced the value of the Company's net operating losses.

IRC Section 382 addresses company ownership changes and specifically limits the utilization of certain deductions and other tax attributes on an annual basis following an ownership change. As a result of the Chapter 11 reorganization and related transactions, the Company experienced an ownership change within the meaning of IRC Section 382 on March 21, 2017. The Company analyzed alternatives available within the IRC to taxpayers in Chapter 11 bankruptcy proceedings in order to minimize the impact of the March 21, 2017 ownership change on its tax attributes. Upon filing the 2017 U.S. Federal income tax return, the Company elected an available alternative which resulted in 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. Upon final determination of tax return amounts for the year ended December 31, 2017, including attribute reduction that occurred on January 1, 2018, the Company has total federal net operating loss carryforwards of $1,011,368 including $760,067 which are subject to limitation due to the ownership change that occurred upon emergence from bankruptcy and $251,301 of post-change net operating loss carryforwards not subject to this limitation. The Company estimates that it will incur an additional $85,863 of post-change net operating loss carryforward not subject to the limitation for the tax year ended December 31, 2018. The limitation did not result in a current tax liability for the tax year ended December 31, 2017 and is not expected to result in a tax liability for the tax year ended December 31, 2018.

(dollars in thousands, except per share amounts)

Other

Other consisted of the following:

	Three months ended September 30, 2018	Nine months ended September 30, 2018
Restructuring	$ —	$ 425
Subleases	402	1,208
Total other expense	$ 402	$ 1,633

Restructuring. We previously 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 is a result of termination benefits for the final slate of employees terminated as a result of the divestiture.

Subleases. Our subleases are comprised of CO_2 compressors that were previously utilized in our EOR operations and leased as capital and operating leases from U.S. Bank but are now subleased to the purchaser of our EOR assets (the "Sublessee"). Minimum payments under the subleases are equal to the original leases. 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 are disclosed in the table above, are reflected in "Other" on our statement of operations while payments on the original capital leases are a reduction of debt and recognition of interest expense. 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. Please see "Note 1— Nature of operations and summary of significant accounting policies"," Note 8— Debt", and "Note 16— Commitments and contingencies" 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 leases.

Joint development agreement

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.

Our drilling and completion costs to date have been exceeding well cost caps specified under the JDA primarily due to inflation in the cost of oilfield services as a result of the rebound in industry conditions. In our negotiation with BCE to cover the inflationary cost increases, BCE had indicated willingness to increase the per well cost caps on remaining wells in exchange for adding more wells to the current program. Since we have achieved our goals to utilize the JDA as a means to delineate our acreage Garfield and Canadian counties, Oklahoma, we do not currently plan for any expansion of the JDA. We have therefore recorded additions to oil and natural gas properties of $7,834 in cumulative drilling and completion costs on JDA wells that have exceeded the well cost caps specified under the JDA.

(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 industry conditions. 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
	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
One-time severance and termination benefits	$ 210	$ 30	$ 1,034	$ 142	$ 608
Professional fees	—	4	—	13	21
Total cost reduction initiatives expense	$ 210	$ 34	$ 1,034	$ 155	$ 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 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	493	858	1,962	2,548	18,790
Rejection of employment contracts	—	—	—	—	4,573
Write off unamortized issuance costs on Prior Credit Facility	—	—	—	—	1,687
Total reorganization items	$ 493	$ 858	$ 2,010	$ 2,548	$ (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 currently should be applied using a modified retrospective approach. Early adoption is permitted. Our planned adoption of the new standard will utilize the transition option that allows us to apply legacy guidance, including disclosure requirements, in the comparative periods presented in the year of adoption. This transition option was one of several practical expedients introduced in a July 2018 guidance update. 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, on July 24, 2018, our Class A common stock began trading on the New York Stock Exchange (“NYSE”) under the symbol “CHAP”. From May 26, 2017, through July 23, 2018, our Class A common stock was quoted on the OTCQB tier of the OTC Markets Group Inc. 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 national exchange. Our Class A and Class B common stock shares equally in dividends and undistributed earnings. Pursuant to our certificate of incorporation, our Class B common stock will convert to Class A common stock at the latest on December 15, 2018. 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017
Numerator for basic and diluted earnings per share				
Net loss	$ (12,068)	$ (19,115)	$ (45,503)	$ (17,433)
Denominator for basic earnings per share				
Weighted average common shares - Basic for Class A and Class B	45,333,745	44,982,142	45,272,595	44,982,142
Denominator for diluted earnings per share				
Weighted average common shares - Diluted for Class A and Class B (1)	45,333,745	44,982,142	45,272,595	44,982,142
Earnings per share				
Basic for Class A and Class B	$ (0.27)	$ (0.42)	$ (1.01)	$ (0.39)
Diluted for Class A and Class B	$ (0.27)	$ (0.42)	$ (1.01)	$ (0.39)
Participating securities excluded from earnings per share calculations				
Unvested restricted stock awards (2)	1,126,669	1,796,943	1,126,669	1,796,943

(1) During the 2017 periods presented, 140,023 warrants were outstanding. All such warrants expired on June 30, 2018. The warrants to purchase shares of our Class A common stock were 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. Figures reflect period end amounts.

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

	Successor		Predecessor
	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
Net cash provided by operating activities included:			
Cash payments for interest	$ 5,755	$ 13,196	$ 4,105
Interest capitalized	(7,155)	(1,245)	(248)
Cash payments for income taxes	$ —	$ 150	$ —
Cash payments for reorganization items	$ 2,161	$ 16,930	$ 11,405
Non-cash investing activities included:			
Asset retirement obligation additions and revisions	$ 1,234	$ 2,746	$ 716
Change in accrued oil and gas capital expenditures	$ 7,222	$ 10,598	$ 5,387

(dollars in thousands, except per share amounts)

Note 4: Debt and capital leases

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

	September 30, 2018	December 31, 2017
8.75% Senior Notes due 2023	$ 300,000	$ —
New Credit Facility	—	127,100
Real estate mortgage note	8,738	9,177
Installment note payable	371	—
Capital lease obligations	12,358	14,361
Unamortized debt issuance costs	(12,263)	(5,979)
Total debt, net	309,204	144,659
Less current portion	3,444	3,273
Total long-term debt, net	$ 305,760	$ 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 or around May 1 and November 1 of each year. On June 29, 2018, we repaid $243,100, representing the entire outstanding balance with proceeds from the issuance of our Senior Notes discussed below. Based on a borrowing base of $265,000, availability on the New Credit Facility as of September 30, 2018, after taking into account letters of credit, was $264,172.

As of June 29, 2018 (the day immediately preceding payment in full of the entire outstanding balance), 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 5.31%.

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 September 30, 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.

Under the New Credit Facility, in the event of asset divestitures which occur between scheduled borrowing base redeterminations, individually or in aggregate amounting to more than 5% of the borrowing base value assigned to the disposed assets, an automatic borrowing base reduction under the Triggering Disposition clause (as defined in the New Credit Facility) would occur. In conjunction with the Triggering Disposition clause, we executed a letter agreement (the "Letter Agreement") with the lenders under our New Credit Facility. The Letter Agreement decreased the borrowing base by $20,000 to $265,000 following the closing of several non-core asset divestitures which included the divestiture of certain properties in the Oklahoma/Texas Panhandle, which closed on July 27, 2018, for gross cash proceeds before selling costs of $17,000 and the conveyance of $629 in liabilities to the buyer, and two additional divestitures which closed in June 2018 for total proceeds of $6,913. The Letter Agreement, which was effective July 27, 2018, also excludes the property divestitures above from future determinations of whether a Triggering Disposition has occurred. See further discussion about these divestitures in "Note 11 – Divestitures."

Our November 2018 borrowing base redetermination is currently in process.

8.75% Senior Notes

On June 29, 2018, we completed the issuance and sale at par of $300,000 in aggregate principal amount of our Senior Notes in a private placement under Rule 144A and Regulation S of the Securities Act of 1933, as amended. The offering costs were $7,337 resulting in net proceeds of $292,663, which we used to repay the New Credit Facility and for general corporate purposes.

The Senior Notes bear interest at a rate of 8.75% per year beginning June 29, 2018 (payable semi-annually in arrears on January 15 and July 15 of each year, beginning on January 15, 2019) and will mature on July 15, 2023.

The Senior Notes are the Company's senior unsecured obligations and rank equal in right of payment with all of the Company's existing and future senior indebtedness, senior to all of the Company's existing and future subordinated indebtedness and effectively subordinated to all of the Company's existing and future secured indebtedness, to the extent of the value of the collateral securing such indebtedness.

The indenture governing our Senior Notes contains certain covenants which limit our ability to:

- incur additional indebtedness or issue certain preferred stock;
- pay dividends or repurchase or redeem capital stock;
- make certain investments;
- incur certain liens;
- enter into certain types of transactions with affiliates;
- sell assets;
- enter into agreements restricting their ability to pay dividends or make other payments;
- consolidate, merge, sell, or otherwise dispose of all or substantially all of their assets; and
- create unrestricted subsidiaries.

Prior to July 15, 2020, the Company may, at its option, redeem all or, from time to time, a part of the Senior Notes at a redemption price equal to 100% of the principal amount thereof, plus an applicable make-whole premium and accrued and unpaid interest, if any, to the date of redemption. On or after July 15, 2020, the Company may, at its option, redeem all or, from time to time, a part of the Senior Notes at a redemption price equal to 100% of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest, if any, to the date of redemption.

On any one or more occasions prior to July 15, 2020, the Company, at its option, may redeem up to 35% of the aggregate principal amount of the Senior Notes with proceeds of one or more qualified equity offerings at a redemption price of 108.75% of the principal amount of the Senior Notes redeemed, plus accrued and unpaid interest, if any, and liquidated damages provided that:

1) at least 60% of the aggregate principal amount of Notes issued under the Indenture remains outstanding after each such redemption; and

2) such redemption occurs within 180 days after the closing of any such qualified equity offering

Upon an Event of Default (as defined in the Indenture), the Trustee or the holders of at least 25% in aggregate principal amount of the outstanding Senior Notes may declare the entire principal of, premium, if any, and accrued and unpaid interest, if any, on all the Senior Notes to be due and payable immediately.

If the Company experiences certain kinds of changes of control, holders of the Senior Notes will be entitled to require the Company to purchase all or a portion of the Senior Notes at 101% of their principal amount, plus accrued and unpaid interest.

Chaparral Energy, Inc. is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding Senior Notes have been fully and unconditionally guaranteed, on a joint and several basis, by all of our wholly owned subsidiaries.

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 terms of 84 months 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.

(dollars in thousands, except per share amounts)

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:

	Three months ended September 30, 2018	Nine months ended September 30, 2018
Revenues:		
Oil	$ 46,576	$ 132,378
Natural gas	9,458	26,584
Natural gas liquids	14,078	34,789
Gross commodity sales	70,112	193,751
Transportation and processing	(4,593)	(11,916)
Net commodity sales	$ 65,519	$ 181,835

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 and nine months ended September 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

(dollars in thousands, except per share amounts)

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. 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 September 30, 2018		
	As reported	**Balances without adoption of ASC 606**	**Effect of change**
Revenues			
Net commodity sales	$ 65,519	$ 70,112	$ (4,593)
Costs and expenses			
Transportation and processing	$ —	$ (4,593)	$ 4,593

	Nine months ended September 30, 2018		
	As reported	**Balances without adoption of ASC 606**	**Effect of change**
Revenues			
Net commodity sales	$ 181,835	$ 193,751	$ (11,916)
Costs and expenses			
Transportation and processing	$ —	$ (11,916)	$ 11,916

(dollars in thousands, except per share amounts)

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.

During the second quarter of 2018, we entered into additional derivative contracts to hedge our exposure to natural gas liquids pricing, specifically propane and natural gasoline, natural gas basis differentials and the WTI NYMEX calendar month average roll ("oil roll"), which is a contractual component of our crude oil sales prices.

The following table summarizes our crude oil derivatives outstanding as of September 30, 2018:

		Weighted average fixed price per Bbl		
Period and type of contract	**Volume MBbls**	**Swaps**	**Purchased puts**	**Sold calls**
2018				
Oil swaps	515	$ 58.21	$ —	$ —
Oil collars	46	$ —	$ 50.00	$ 60.50
Oil roll swaps	150	$ 0.59	$ —	$ —
2019				
Oil swaps	1,562	$ 55.90	$ —	$ —
Oil roll swaps	530	$ 0.52	$ —	$ —
2020				
Oil swaps	1,548	$ 49.54	$ —	$ —
Oil roll swaps	410	$ 0.38	$ —	$ —
2021				
Oil swaps	543	$ 44.34	$ —	$ —
Oil roll swaps	150	$ 0.30	$ —	$ —

The following table summarizes our natural gas derivatives outstanding as of September 30, 2018:

Period and type of contract	**Volume BBtu**	**Weighted average fixed price per MMBtu**
2018		
Natural gas swaps	2,519	$ 2.88
Natural gas basis swaps	1,500	$ 0.70
2019		
Natural gas swaps	7,632	$ 2.81
Natural gas basis swaps	2,500	$ 0.70
2020		
Natural gas swaps	3,600	$ 2.77

(dollars in thousands, except per share amounts)

The following table summarizes our natural gas liquid derivatives outstanding as of September 30, 2018:

Period and type of contract	Volume Gallons	Weighted average fixed price per gallon
2018		
Natural gasoline swaps	1,512	$ 1.55
Propane swaps	3,528	$ 0.88
2019		
Natural gasoline swaps	4,956	$ 1.39
Propane swaps	11,466	$ 0.74
2020		
Natural gasoline swaps	1,890	$ 1.39
Propane swaps	4,284	$ 0.74

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 at September 30, 2018			As at December 31, 2017		
	Assets	Liabilities	Net value	Assets	Liabilities	Net value
Natural gas derivative contracts (1)	$ 683	$ (297)	$ 386	$ 1,332	$ (1,054)	$ 278
Crude oil derivative contracts (2)	119	(64,325)	(64,206)	—	(13,404)	(13,404)
NGL derivative contracts	—	(5,127)	(5,127)	—	—	—
Total derivative instruments	802	(69,749)	(68,947)	1,332	(14,458)	(13,126)
Less:						
Netting adjustments (3)	802	(802)	—	1,332	(1,332)	—
Derivative instruments - current	—	(29,905)	(29,905)	—	(8,959)	(8,959)
Derivative instruments - long-term	$ —	$ (39,042)	$ (39,042)	$ —	$ (4,167)	$ (4,167)

(1) The fair value of our natural gas basis swaps, included herein, was $172 at September 30, 2018.
(2) The fair value of our oil roll swaps, included herein, was $73 at September 30, 2018.
(3) 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.

In October and November 2018, we entered into several derivative contracts with varying maturities outlined below:

Period and type of contract	Volume MBbls	Weighted average fixed price per Bbl Swaps
2019		
Oil swaps	220	$ 63.51
2020		
Oil swaps	100	$ 61.64

(dollars in thousands, except per share amounts)

Period and type of contract	Volume BBtu	Weighted average fixed price per MMBtu
2018		
Natural gas basis swaps	681	$ (0.52)
2019		
Natural gas basis swaps	2,481	$ (0.66)
Natural gas swaps	660	$ 2.89

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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
Change in fair value of commodity price derivatives	(16,804)	(22,236)	(55,822)	(19,232)	$ 46,721
Settlements (paid) received on commodity price derivatives	(6,873)	6,788	(16,642)	15,143	1,285
Total derivative (losses) gains	(23,677)	(15,448)	(72,464)	(4,089)	$ 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 September 30, 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 and oil roll 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 and natural gas basis swaps. 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 and proprietary pricing curves. 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 at September 30, 2018			As at December 31, 2017		
	Derivative assets	Derivative liabilities	Net assets (liabilities)	Derivative assets	Derivative liabilities	Net assets (liabilities)
Significant other observable inputs (Level 2)	$ 630	$ (69,172)	$ (68,542)	$ 1,332	$ (14,163)	$ (12,831)
Significant unobservable inputs (Level 3)	172	(577)	(405)	—	(295)	(295)
Netting adjustments (1)	(802)	802	—	(1,332)	1,332	—
	$ —	$ (68,947)	(68,947)	$ —	$ (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)	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 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	(1,069)	(259)	813
Settlements paid	959	—	—
Ending balance	$ (405)	$ 456	$ 715
(Losses) gains relating to instruments still held at the reporting date included in derivative (losses) gains for the period	$ (342)	$ (259)	$ 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 nine 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 nine months ended September 30, 2018, were discounted with a credit-adjusted risk-free rate ranging from 6.92% to 8.77%. For the properties added during the period from March 22, 2017, through September 30, 2017, a credit-adjusted risk-free rate range from 5.20% to 7.63% 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.

(dollars in thousands, except per share amounts)

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

	September 30, 2018		December 31, 2017	
Level 2	Carrying value (1)	Estimated fair value	Carrying value (1)	Estimated fair value
8.75% Senior Notes due 2023	$ 300,000	$ 299,718	$ —	$ —
New Credit Facility	—	—	127,100	127,100
Other secured debt	9,109	9,109	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. The fair value of our Senior Notes was estimated based on quoted market prices.

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 September 30, 2018, the counterparties to our open derivative contracts consisted of five 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
September 30, 2018						
Derivative assets	$ 802	$ (802)	$ —	$ —	$ —	$ —
Derivative liabilities	(69,749)	802	(68,947)	—	—	(68,947)
	$ (68,947)	$ —	$ (68,947)	$ —	$ —	$ (68,947)
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 $69,749 before offsets at September 30, 2018.

(dollars in thousands, except per share amounts)

Note 8: Asset retirement obligations

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

Balance at January 1, 2018	$	35,990
Liabilities incurred in current period		632
Liabilities settled or disposed in current period (1)		(12,900)
Revisions in estimated cash flows		602
Accretion expense		1,515
Balance at September 30, 2018	$	25,839
Less current portion included in accounts payable and accrued liabilities		1,481
Asset retirement obligations, long-term	$	24,358

(1) Decrease is primarily a result of property divestitures as discussed in Note 11 - "Divestitures."

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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
Cash LTIP expense (net of amounts capitalized)	$ 185	$ 493	$ 473	$ 1,100	$ 5
Cash LTIP awarded	127	2,316	174	5,637	—
Cash LTIP payments	1,166	1,285	1,183	1,285	42

As of September 30, 2018, the outstanding liability accrued for our Cash LTIP, based on requisite service provided, was $1,182. In October 2018, the Cash LTIP plan was replaced by the Chaparral Energy Long Term Incentive Plan (the "Employee LTIP") discussed below.

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.

(dollars in thousands, except per share amounts)

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 or market-based vesting 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 for awards with service and performance conditions.

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 or market-based conditions established each year which generally relate to profitability, stock returns, drilling results and other strategic goals.

As of September 30, 2018, performance or market-based goals have not been established for Performance Shares allocated for vesting subsequent to 2018 and hence a grant date with respect to those tranches has not been established for accounting purposes and expense has not been recognized thus far. Vesting conditions for Performance Shares vesting in 2018 were 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. Of the Performance Shares scheduled for vesting in 2018, 20% are allocated to a market condition that is based on our stock return relative to a group of peer companies. The fair value of these market condition shares was estimated utilizing a Monte Carlo simulation with stock price volatility, the risk free rate, dividend yields and stock price correlation among peer companies as primary inputs into the model.

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

	Time Shares			Performance Shares	
	Weighted average award date fair value	Restricted shares	Vest date fair value	Weighted average award date fair value	Restricted shares
	($ per share)			($ per share)	
Unvested and outstanding at January 1, 2018	$ 20.11	1,403,626		$ 20.15	$ 269,476
Granted	$ 18.75	41,250		$ 18.75	$ 13,750
Vested	$ 20.05	(435,980)	$ 7,717	$ —	$ —
Forfeited	$ 20.05	(130,972)		$ 20.05	$ (34,481)
Unvested and outstanding at September 30, 2018	$ 20.09	877,924		$ 20.10	$ 248,745

2018 Employee LTIP

On October 1, 2018, we granted 130,008 restricted stock units ("RSUs") under the Employee LTIP. Of these grants, 92,017 RSUs are to be settled in stock upon vesting while 37,991 RSUs are to be settled in cash. These awards, which are service-based, will vest in equal installments over a three-year period.

Companywide stock award

New employees are eligible for a grant of 100 shares subsequent to being employed for a certain period of time. There are no vesting requirements for these awards and thus compensation is recognized in full on the award date based on the closing price of our common stock on that date. In October 2018, 600 shares were awarded to new employees which were the first of such awards in 2018.

Stock-based compensation cost

Compensation cost is calculated net of forfeitures. As allowed by recent accounting guidance, we 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. For awards with market conditions, expense is recognized on the entire value of the award regardless of the vesting outcome so long as the participant remains employed.

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:

(dollars in thousands, except per share amounts)

	Successor				Predecessor
	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
Stock-based compensation cost	$ 3,112	$ 3,577	$ 11,027	$ 3,577	$ 194
Less: stock-based compensation cost capitalized	(807)	(801)	(2,428)	(801)	(39)
Stock-based compensation expense	$ 2,305	$ 2,776	$ 8,599	$ 2,776	$ 155
Number of vested shares repurchased	—	—	256,895	—	—
Payments for stock-based compensation	$ —	$ —	$ 4,872	$ —	$ —

Based on a quarter end market price of $17.62 per share of our Class A common stock, the aggregate intrinsic value of all restricted shares outstanding was $19,852 as of September 30, 2018. The repurchases of shares and associated payments disclosed above were primarily for tax withholding and are reflected as treasury stock transactions on our consolidated statements of stockholders' equity. As of September 30, 2018, and December 31, 2017, there were no accrued payroll and benefits payable included for stock-based compensation costs expected to be settled within the next twelve months. Unrecognized stock-based compensation cost of approximately $8,831 as of September 30, 2018, is expected to be recognized over a weighted-average period of 0.9 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 September 30, 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 nine months ended September 30, 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 ("Petition Date"), 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 which were initiated prior to the Petition Date, 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 putative 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 the legal proceedings were filed prior to the Petition Date and 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. As of November 9, 2018, the Tenth Circuit has not ruled.

On January 17, 2017, the Naylor Trial Court certified a modified class of plaintiffs in the Naylor Trial Court 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. 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.

Pursuant to the Reorganization Plan, if the plaintiffs ultimately prevail on the merits of their claims, any liability arising under judgment or settlement of the plaintiff's claims would be satisfied through the issuance of 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, Oklahoma 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. Plaintiffs petitioned for rehearing on May 21, 2018. The deadline to appeal the order of the Tenth Circuit passed without an appeal being filed.

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 were 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. On August 13, 2018, the court granted our motion to dismiss, and on August 16, 2018 issued an order striking the class allegations from the Second Amended Complaint. On August 30, 2018, plaintiffs filed a motion for a permissive appeal with the United States Court of Appeals for the Tenth Circuit, challenging the order dismissing the class allegations.

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 heard our objection, and on February 9, 2018 granted our objection to class treatment of the proof of claim. To the extent the appeal to the Tenth Circuit disputes the dismissal of claims against us, we will 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 vigorously defend 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, 2017, 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 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, *supra*. Despite the dismissal of the class allegations in the *West* case, the stay has not been lifted. 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 *Lisa West et al. v. ABC Oil Company, Inc*. Despite dismissal of the class allegations in the *West* case, the stay has not been lifted. When the stay is lifted, we will dispute the plaintiffs' claims, dispute the remedies requested are available under Oklahoma law, and vigorously defend the case.

Hallco Petroleum, Inc. v. Chaparral Energy, L.L.C. On November 7, 2017, Hallco Production, LLC ("Hallco") filed a lawsuit against us in the District Court of Kay County, State of Oklahoma. Plaintiffs alleged carbon dioxide which was injected for enhanced oil recovery in wells operated by us migrated to wells operated by Hallco, damaging its salt water disposal well and therefore preventing operation of all wells in the unit. Plaintiffs allege the migration of carbon dioxide constituted trespass, and further allege negligence and nuisance, and see damages in excess of $75. Because we sold the EOR wells on November 17, 2017, Hallco filed an amended petition on March 6, 2018 to add the purchaser as a defendant in the lawsuit, alleging the damage is ongoing. We dispute the plaintiff's 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, quiet title actions, personal injury claims, employment claims, and other matters which arise in the ordinary course of business. These proceedings may include allegations of damages from induced earthquakes, which we will vigorously defend as necessary. 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 September 30, 2018, include contracts for four drilling rigs of which two contracts were signed in September 2018 for durations through the end of 2019. Our commitment as of September 30, 2018, on the two long term drilling rig contracts was $16,524. Other than the changes described herein, the issuance of Senior Notes and repayment of the New Credit Facility described in “Note 4—Debt and capital leases,” there were no material changes to our contractual commitments since December 31, 2017.

Note 11: Divestitures

For the nine months ended September 30, 2018, we received total cash proceeds of $36,335 on various non-core oil and gas assets, property and equipment disposals. Included in these disposals were:

- A divestiture of certain properties in the Oklahoma/Texas Panhandle for gross cash proceeds before selling costs of $17,000 and the conveyance of $629 in liabilities to the buyer, all of which are subject to customary post-close adjustments. The purchaser of these assets is a company affiliated with Mark A. Fischer, our former Chief Executive Officer and former Chairman of the Board.
- A divestiture of certain saltwater disposal infrastructure where we received proceeds of $8,299 in September 2018 with an additional $1,205 received in the fourth quarter of 2018.
- Disposals of various other non-core assets resulting in proceeds of approximately $11,279 for the nine months ended September 30, 2018, followed by additional disposals for proceeds of $5,989 in October 2018.

As the properties above did not represent a material portion of our oil and natural gas reserves, individually or in the aggregate, no gain or loss was recognized on these disposals and instead, we reduced our full cost pool by the amount of the net proceeds without significant alteration to our depletion rate.

We have recently entered into service agreements with two providers to dispose, via pipeline or truck, salt water produced by our wells within areas that encompass Kingfisher, Garfield and Canadian Counties, Oklahoma. The agreements covering Kingfisher and Garfield Counties, Oklahoma are for 15 years and specify fixed rates per barrel according to age of the well. The agreement covering Canadian County, Oklahoma is for 5 years and specifies per barrel rates that vary according to volume of water disposed.

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

On May 9, 2016, Chaparral Energy, Inc. and its subsidiaries including Chaparral Energy, L.L.C., Chaparral Resources, L.L.C., Chaparral Real Estate, L.L.C., Chaparral CO_2 , 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., and 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 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 and nine months ended September 30, 2018 (Successor), the three months ended September 30, 2017 (Successor), and the periods of March 22, 2017, through September 30, 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 third quarter of 2018 includes the following highlights:

- We grew net production from our STACK play to 1,441 MBoe and 3,749 MBoe for the three and nine months ended September 30, 2018, an increase of 53% and 49% from the prior year periods.
- Total company production was 1,964 MBoe and 5,496 MBoe for the three and nine months ended September 30, 2018, a decrease of 13% and 15% from the prior year periods. The decreases are primarily a result of the sale of our EOR assets in late 2017. Excluding production from our divested EOR assets, total company production increased 11% and 11% for the three and nine months ended September 30, 2018, respectively, compared to the prior year periods.
- We incurred a net loss of $12.1 million during the quarter which included a $16.8 million non-cash fair value loss on our derivatives. For the nine months ended September 30, 2018, we incurred a net loss of $45.5 million which included a $55.8 million non-cash fair value loss on our derivatives.
- Our lease operating expense per Boe decreased to $6.36/Boe, a decrease of 41% from the prior year quarter, primarily driven by the divestitures of our EOR assets in late 2017 and of our non-core assets in 2018, which were assets characterized by higher operating costs compared to our STACK assets. Lease operating expense per Boe in our STACK play of $4.34 decreased compared to the second quarter of 2018 and was approximately flat compared to the prior year quarter.

- We brought online 12 new gross operated wells during the third quarter, five of which were part of our joint drilling program discussed below. For the nine months ended September 30, 2018, we brought online 35 new gross operated wells, 17 of which were part of our joint drilling program.
- We concluded the initial closing on the sale of certain saltwater disposal assets in September for proceeds of $8.3 million with an additional $1.2 million received in the fourth quarter of 2018. Our total net cash proceeds for various asset divestitures during the nine months ended September 30, 2018, was $36.3 million.
- Our oil and natural gas capital expenditures for the nine months ended September 30, 2018, was $265.0 million, with $147.2 million incurred for drilling and completions and $107.9 million on acquisitions.
- On July 24, 2018, we transferred our stock exchange listing for our Class A common stock from the OTCQB market to the New York Stock Exchange (NYSE) and began trading under the new ticker symbol “CHAP.” Upon the opening of NYSE trading, our Class A common stock ceased trading under the symbol “CHPE” on the OTCQB market.

Capital development

We incurred capital expenditures of $265.0 million for the nine months ended September 30, 2018, of which $147.2 million was for drilling and completions, which included bringing online five wells drilled in the prior year, drilling and bringing online 13 wells, drilling nine wells scheduled to be brought online in late 2018/early 2019, and participating in wells operated by others. We were operating three horizontal drilling rigs in the STACK during the third quarter and added a fourth in October 2018. Our drilling activity in 2018 has encompassed drilling wells in Kingfisher, Canadian and Garfield counties in Oklahoma. Our capital expenditures for the nine months ended September 30, 2018, also includes $107.9 million on acquisitions, of which approximately half is comprised of our 7,000 acre Kingfisher County leasehold purchase in January 2018. In August 2018, our Board approved an increase to our oil and natural gas capital budget resulting in an expanded budget with a range of $300.0 million to $325.0 million. Our capital budget was expanded to recognize working interest increases in certain wells we have recently drilled, additional leasehold acquisitions when attractive opportunities were available, cost inflation in oilfield services and the addition of a fourth drilling rig.

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. The provisions of the JDA are described more fully in “Note 1—Nature of operations and summary of significant accounting policies” in Item 1. Financial Statements of this report. During the nine months ended September 30, 2018, we drilled and brought online 16 wells and brought online one well drilled in the prior year. As of September 30, 2018, we have drilled and completed 20 wells under the JDA.

Our drilling and completion costs to date have exceeded the well cost caps specified under the JDA primarily due to inflation in the cost of oilfield services as a result of the rebound in industry conditions. In our negotiation with BCE to cover the inflationary cost increases, BCE had indicated willingness to increase the per well cost caps on remaining wells in exchange for adding more wells to the current program. Since we have achieved our goal of utilizing the JDA as a means to delineate our acreage in Garfield and Canadian counties, Oklahoma, we do not currently plan for any expansion of the JDA. We have therefore recorded additions to oil and natural gas properties of $7.8 million in cumulative costs exceeding the cost caps for the nine months ended September 30, 2018, and estimate that an additional $6.1 million of increases will be incurred and recognized on remaining wells in the JDA. These increases to our capital expenditures do not change our pre-reversionary interest of 15%.

Termination of Stockholders Agreement

On July 24, 2018, in connection with the listing of our Class A common stock on the New York Stock Exchange, the Stockholders Agreement, by and among the Company and the stockholders named therein, dated as of March 21, 2017, as amended by the First Amendment thereto, dated as of March 6, 2018, terminated pursuant to its terms.

Price uncertainty and the full-cost ceiling impairment

Recent commodity price improvement has increased our realized price per barrel of crude oil by approximately 50% during the third quarter of 2018 compared to the prior year quarter. However, 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 as disclosed in Item 3. Quantitative and Qualitative Disclosures About Market Risk. 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.

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 be recognized immediately but could be spread over several reporting periods. Ceiling test write-downs were not required during the nine months ended September 30, 2018.

Results of operations

Production

Production volumes by area were as follows (MBoe):

	Successor				Predecessor
	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
STACK Areas:					
STACK - Kingfisher County	470	564	1,680	1,135	423
STACK - Canadian County	494	245	1,090	462	142
STACK - Garfield County	373	116	778	195	57
STACK - Other	104	19	201	67	34
Total STACK Areas	1,441	944	3,749	1,859	656
EOR Areas	—	491	—	1,070	445
Other	523	821	1,747	1,733	695
Total	1,964	2,256	5,496	4,662	1,796

Our total net production of 1,964 MBoe for the three months ended September 30, 2018, decreased approximately 13% compared to net production for the prior year quarter. For the nine months ended September 30, 2018, our net production of 5,496 MBoe decreased approximately 15% compared to net production for comparable period in 2017. The decreases were primarily a result of the sale of our EOR assets in November 2017 and non-core asset divestitures throughout 2018 partially offset by production growth in our STACK Area. Excluding production from divested EOR assets, net production increased 11% and 11% for the three and nine months ended September 30, 2018, respectively, compared to the prior year periods due to production growth from our STACK play. Net production from our STACK play was 1,441 MBoe and 3,749 MBoe for the three and nine months ended September 30, 2018, an increase of 53% and 49% from the prior year periods. 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 deductions beginning in January 1, 2018. 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 September 30, 2018	**Three months ended September 30, 2017**	**Nine months ended September 30, 2018**	**Period from March 22, 2017 through September 30, 2017**	**Period from January 1, 2017 through March 21, 2017**
Commodity sales (in thousands):					
Oil	$ 46,576	$ 57,746	$ 132,378	$ 121,574	$ 51,847
Natural gas	9,458	9,710	26,584	20,164	9,140
Natural gas liquids	14,078	8,491	34,789	16,065	5,544
Gross commodity sales	$ 70,112	$ 75,947	$ 193,751	$ 157,803	$ 66,531
Transportation and processing	(4,593)	—	(11,916)	—	—
Net commodity sales	$ 65,519	$ 75,947	$ 181,835	$ 157,803	$ 66,531
Production:					
Oil (MBbls)	664	1,238	2,006	2,606	1,036
Natural gas (MMcf)	4,539	3,836	12,491	7,778	3,046
Natural gas liquids (MBbls)	543	379	1,408	760	252
MBoe	1,964	2,256	5,496	4,662	1,796
Average daily production (Boe/d)	21,342	24,522	20,131	24,155	22,450
Average sales prices (excluding derivative settlements):					
Oil per Bbl	$ 70.14	$ 46.64	$ 65.99	$ 46.65	$ 50.05
Natural gas per Mcf	$ 2.08	$ 2.53	$ 2.13	$ 2.59	$ 3.00
NGLs per Bbl	$ 25.93	$ 22.40	$ 24.71	$ 21.14	$ 22.00
Transportation and processing per Boe	$ (2.34)	$ —	$ (2.17)	$ —	$ —
Average sales price per Boe	$ 33.37	$ 33.66	$ 33.09	$ 33.85	$ 37.04

Our gross commodity sales (excludes transportation and processing deductions) for the three and nine months ended September 30, 2018, of $70.1 million and $193.8 million, respectively, decreased approximately 8% and 14% compared to gross commodity sales for the prior year periods. The decrease for the three months ended September 30, 2018, compared to the prior year quarter is due to a decrease in crude oil production and lower natural gas prices partially offset by increases in natural gas and natural gas liquids production and higher crude oil and natural gas liquids prices. These same trends also resulted in the decrease in gross commodity sales for the nine months ended September 30, 2018, compared to the prior year period.

Since production from our divested EOR assets was predominantly in crude oil, our net crude oil production for the three and nine months ended September 30, 2018, decreased 46% and 45%, respectively compared to the prior year periods. In the meantime, as a result of growth in our STACK play, our net natural gas production for the three and nine months ended September 30, 2018, increased 18% and 15%, respectively, compared to the prior year periods and our net natural gas liquids production for the three and nine months ended September 30, 2018, increased 43% and 39%, respectively, compared to the prior year periods.

(in thousands)	Three months ended September 30, 2018 vs. 2017 Sales change	Three months ended September 30, 2018 vs. 2017 Percentage change in sales	Nine months ended September 30, 2018 vs. 2017 Sales change	Nine months ended September 30, 2018 vs. 2017 Percentage change in sales
Change in oil sales due to:				
Prices	$ 15,601	27.0 %	$ 36,867	21.3 %
Production	$ (26,771)	(46.4)%	$ (77,910)	(44.9)%
Total change in oil sales	$ (11,170)	(19.3)%	$ (41,043)	(23.7)%
Change in natural gas sales due to:				
Prices	$ (2,031)	(20.9)%	$ (7,240)	(24.7)%
Production	$ 1,779	18.3 %	$ 4,520	15.4 %
Total change in natural gas sales	$ (252)	(2.6)%	$ (2,720)	(9.3)%
Change in natural gas liquids sales due to:				
Prices	$ 1,913	22.5 %	$ 4,730	21.9 %
Production	$ 3,674	43.3 %	$ 8,450	39.1 %
Total change in natural gas liquids sales	$ 5,587	65.8 %	$ 13,180	61.0 %

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. Transportation and processing deductions were $4.6 million and $11.9 million for the three and nine months ended September 30, 2018, respectively, representing increases of 56% and 42% compared to the prior year periods. Transportation and processing deductions were higher on a dollar basis as a result of increased production of natural gas and natural gas liquids as well as higher rates. The increases have been driven by production growth in our STACK area where we have experienced higher transportation and processing costs compared to our other operating areas due to new infrastructure being built in the area. 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. In addition, transportation and processing deductions were also 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 while natural gas and natural gas liquids comprise a larger proportion of our current production on a Boe basis.

	Successor				Predecessor
	Three months ended September 30, 2018 (1)	Three months ended September 30, 2017 (2)	Nine months ended September 30, 2018 (1)	March 22, 2017 through September 30, 2017 (2)	January 1, 2017 through March 21, 2017 (2)
Transportation and processing charges (in thousands)	$ 4,593	$ 2,942	$ 11,916	$ 6,370	$ 2,034
Transportation and processing charges per Boe	$ 2.34	$ 1.30	$ 2.17	$ 1.37	$ 1.13

(1) Reflected as a revenue deduction on our consolidated statements of operations.
(2) Reflected as an expense on our consolidated statements of operations.

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.

During the second quarter of 2018, we entered into additional derivative contracts to hedge our exposure to natural gas liquids pricing, specifically propane and natural gasoline, natural gas basis differentials and the WTI NYMEX calendar month average roll ("oil roll"), which is a contractual component of our crude oil sales prices.

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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
Oil (per Bbl):					
Before derivative settlements	$ 70.14	$ 46.64	$ 65.99	$ 46.65	$ 50.05
After derivative settlements	$ 60.65	$ 51.49	$ 58.07	$ 52.01	$ 51.20
Post-settlement to pre-settlement price	86.5%	110.4%	88.0%	111.5%	102.3%
Natural gas liquids (per Bbl):					
Before derivative settlements	$ 25.93	$ 22.40	$ 24.71	$ 21.14	$ 22.00
After derivative settlements	$ 25.20	*	$ 24.45	*	*
Post-settlement to pre-settlement price	97.2%	*	98.9%	*	*
Natural gas (per Mcf):					
Before derivative settlements	$ 2.08	$ 2.53	$ 2.13	$ 2.59	$ 3.00
After derivative settlements	$ 2.05	$ 2.74	$ 2.10	$ 2.74	$ 3.03
Post-settlement to pre-settlement price	98.6%	108.3%	98.6%	105.8%	101.0%

* Not applicable as we did not hedge NGL prices prior to the second quarter of 2018.

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

(in thousands)	September 30, 2018	December 31, 2017
Derivative (liabilities) assets:		
Crude oil derivatives (1)	$ (64,206)	$ (13,404)
Natural gas derivatives (2)	386	278
NGL derivatives	(5,127)	—
Net derivative (liabilities) assets	$ (68,947)	$ (13,126)

(1) The fair value of our oil roll swaps, included herein, was $73 at September 30, 2018.
(2) The fair value of our natural gas basis swaps, included herein, was $172 at September 30, 2018.

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

	Three months ended September 30,			
	2018		2017	
(in thousands)	Non-cash fair value adjustment	Settlements (paid) received	Non-cash fair value adjustment	Settlements (paid) received
Derivative (losses) gains:				
Crude oil derivatives	$ (14,026)	$ (6,307)	$ (21,350)	$ 5,997
Natural gas derivatives	357	(174)	(886)	791
NGL derivatives	(3,135)	(392)	—	—
Derivative (losses) gains	$ (16,804)	$ (6,873)	$ (22,236)	$ 6,788

	Successor				Predecessor	
	Nine months ended September 30, 2018		Period from March 22, 2017 through September 30, 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	$ (50,802)	$ (15,889)	$ (19,235)	$ 13,958	$ 42,819	$ 1,192
Natural gas derivatives	108	(396)	3	1,185	3,902	93
NGL derivatives	(5,128)	(357)	—	—	—	—
Derivative (losses) gains	$ (55,822)	$ (16,642)	$ (19,232)	$ 15,143	$ 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
Lease operating expenses:					
STACK Areas	$ 6,251	$ 4,051	$ 18,569	$ 7,772	$ 2,247
EOR Areas	—	9,078	—	19,749	8,488
Other	6,242	11,080	23,476	24,006	9,206
Total lease operating expenses	$ 12,493	$ 24,209	$ 42,045	$ 51,527	$ 19,941
Lease operating expenses per Boe:					
STACK Areas	$ 4.34	$ 4.29	$ 4.95	$ 4.18	$ 3.43
EOR Areas	$ —	$ 18.49	$ —	$ 18.46	$ 19.07
Other	$ 11.93	$ 13.50	$ 13.44	$ 13.85	$ 13.25
Lease operating expenses per Boe	$ 6.36	$ 10.73	$ 7.65	$ 11.05	$ 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.

LOE for the three months ended September 30, 2018, was $12.5 million, a decrease of 48% compared to the prior year quarter. The decrease was due to the divestiture of our EOR assets, which were historically more expensive to operate than traditional industry operations, and the divestiture of other high-cost non-core assets in 2018 partially offset by LOE increases in the STACK where we are growing production. LOE per Boe of $6.36 was 41% lower than the prior year quarter primarily as a result of the divestitures and the STACK growth described above. LOE per Boe of $4.34 in our STACK Areas was flat compared to the prior year quarter.

LOE for the nine months ended September 30, 2018, was $42.0 million or $7.65 per Boe, a decrease of 41% or 31%compared to the prior year period. The decrease in LOE on a dollar and per Boe are due to same factors described above but are also impacted by 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
Bonus expense	$ 182	$ 239	$ 560	$ 2,676	$ —

Production taxes (which include severance and valorem taxes)

	Successor				Predecessor
	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
Production taxes (in thousands)	$ 4,028	$ 4,536	$ 9,473	$ 8,235	$ 2,417
Production taxes per Boe	$ 2.05	$ 2.01	$ 1.72	$ 1.77	$ 1.35
Production taxes as % of commodity sales	5.7%	6.0%	4.9%	5.2%	3.6%

Production taxes for the three and nine months ended September 30, 2018, of $4.0 million and $9.5 million, respectively, were 11% and 11% lower than the prior year periods. The decreases were a result of lower gross commodity sales partially offset by legislative increases in production tax rates as described below. Production taxes on a per Boe basis were relatively flat across the time periods despite the enacted production tax increases as our production mix has shifted towards a higher proportion of natural gas and natural gas liquids which are lower in value compared to crude oil on a per Boe basis.

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 from 2% to 5% during the first three years of production on horizontal wells spudded after July 1, 2015.

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

	Successor				Predecessor
	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
DD&A (in thousands):					
Oil and natural gas properties (1)	$ 20,234	$ 29,635	$ 56,875	$ 61,309	$ 23,442
Property and equipment	2,018	2,532	6,890	5,123	1,473
Total DD&A	$ 22,252	$ 32,167	$ 63,765	$ 66,432	$ 24,915
DD&A per Boe:					
Oil and natural gas properties (1)	$ 10.30	$ 13.14	$ 10.35	$ 13.15	$ 13.05
Other fixed assets	$ 1.03	$ 1.12	$ 1.25	$ 1.10	$ 0.82
Total DD&A per Boe	$ 11.33	$ 14.26	$ 11.60	$ 14.25	$ 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, oil and natural gas DD&A for the three and nine months ended September 30, 2018, of $20.2 million and $56.9 million, respectively was 32% and 33% lower than the prior year periods due to lower production and a lower DD&A rate.

General and administrative expenses ("G&A")

	Successor				Predecessor
(in thousands)	**Three months ended September 30, 2018**	**Three months ended September 30, 2017**	**Nine months ended September 30, 2018**	**Period from March 22, 2017 through September 30, 2017**	**Period from January 1, 2017 through March 21, 2017**
G&A and cost reduction initiatives:					
Gross G&A expenses	$ 12,202	$ 12,709	$ 37,187	$ 30,795	$ 8,117
Capitalized exploration and development costs	(3,181)	(2,785)	(8,469)	(6,154)	(1,274)
Net G&A expenses	9,021	9,924	28,718	24,641	6,843
Cost reduction initiatives	210	34	1,034	155	629
Net G&A and cost reduction initiatives	$ 9,231	$ 9,958	$ 29,752	$ 24,796	$ 7,472
Net G&A expense per Boe	$ 4.59	$ 4.40	$ 5.23	$ 5.29	$ 3.81
Net G&A and cost reduction initiatives per Boe	$ 4.70	$ 4.41	$ 5.41	$ 5.32	$ 4.16

Net G&A of $9.0 million for the three months ended September 30, 2018, decreased from the prior year quarter primarily due to lower total compensation and benefits in conjunction with a reduction in headcount compared to the prior year. Net G&A of $28.7 million for the nine months ended September 30, 2018, was lower than the prior year period primarily due to a decrease in expense associated with salaries and our long term cash incentive plan, also in connection with our headcount reduction. On a year to date basis, 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 nine months ended September 30, 2018, was due to year-to-date requisite service costs under our new Management Incentive Plan (the "MIP") which was adopted in August 2017. In contrast, stock compensation for the successor period in 2017 only included a month and a half of expense subsequent to the adoption of the MIP. 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:

	Successor				Predecessor
(in thousands)	**Three months ended September 30, 2018**	**Three months ended September 30, 2017**	**Nine months ended September 30, 2018**	**Period from March 22, 2017 through September 30, 2017**	**Period from January 1, 2017 through March 21, 2017**
Bonus expense, gross	$ 1,166	$ 888	$ 2,646	$ 8,868	$ —
Stock compensation, gross	3,112	3,577	11,027	3,577	194
	$ 4,278	$ 4,465	$ 13,673	$ 12,445	$ 194

Other than the impact of the transactions described above, gross G&A expense was lower for the three and nine months ended September 30, 2018, compared to the prior year periods, due to decreased salaries and benefits as a result of lower headcount and a decrease in professional fees incurred.

Other

Other consists of the following (in thousands):

	Three months ended September 30, 2018	Nine months ended September 30, 2018
Restructuring	$ —	$ 425
Subleases	402	1,208
Total other expense	$ 402	$ 1,633

Restructuring expense. We previously 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 is a result of termination benefits for the final slate of employees terminated as a result of the divestiture.

Subleases. Our subleases are comprised of CO_2 compressors that were previously utilized in our EOR operations and leased as capital and operating leases from U.S. Bank but are now subleased to the purchaser of our EOR assets (the “Sublessee”). Minimum payments under the subleases are equal to the original leases. 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 are reflected in “Other” on our statement of operations while payments on the original capital leases are a reduction of debt and recognition of interest expense. 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. Please see “Note 1— Nature of operations and summary of significant accounting policies”,” Note 8— Debt”, and “Note 16 — Commitments and contingencies” 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 leases.

Income taxes

We did not record any net deferred tax benefit for the three and nine months ended September 30, 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
New Credit Facility or Exit Revolver	$ —	$ 1,769	$ 5,118	$ 3,470	$ —
Senior Notes	6,562	—	6,708	—	—
Exit Term Loan including amortization of discount	—	3,493	—	7,405	—
Prior Credit Facility	—	—	—	—	5,193
Bank fees, other interest and amortization of issuance costs	1,283	671	2,644	1,354	917
Interest expense, gross	7,845	5,933	14,470	12,229	6,110
Capitalized interest	(3,640)	(650)	(7,155)	(1,245)	(248)
Total interest expense	$ 4,205	$ 5,283	$ 7,315	$ 10,984	$ 5,862
Average borrowings (excluding amounts subject to compromise)	$ 321,752	$ 321,974	$ 261,001	$ 310,490	$ 470,915

Interest expense for the three and nine months ended September 30, 2018, of \$4.2 million and \$7.3 million, respectively, was lower than the prior year periods, primarily due to an increase in capitalized interest. Capitalized interest for the three and nine months ended September 30, 2018, of \$3.6 million and \$7.2 million, respectively, increased compared to the prior year periods due to the larger carrying amount of unevaluated purchased non-producing leasehold during the past 12 months which included our 7,000 acre leasehold purchase for $60.6 million 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 and instead capitalized interest is calculated based only on the carrying value of actual purchased leasehold.

Gross interest expense for the three months ended September 30, 2018, of $7.8 million was higher than the prior year period as debt in current quarter was attributable to our Senior Notes which carried a higher interest rate than our secured revolving credit facility. Gross interest expense for the nine months ended September 30, 2018, of $14.5 million was lower than the prior year primarily due to a lower average balance of debt outstanding.

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 September 30, 2018	**Three months ended September 30, 2017**	**Nine months ended September 30, 2018**	**Period from March 22, 2017 through September 30, 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	493	858	1,962	2,548	18,790
Rejection of employment contracts	—	—	—	—	4,573
Write off unamortized issuance costs on Prior Credit Facility	—	—	—	—	1,687
Total reorganization items	$ 493	$ 858	$ 2,010	$ 2,548	$ (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.

Liquidity and capital resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our revolving credit facility or issuance of debt and proceeds from hedge settlements. Additionally, in recent years asset dispositions and our joint development arrangement have provided a source of cash flow for enhancing liquidity. In 2018, asset divestitures have been a significant source of liquidity and we expect to generate aggregate proceeds of $50 million to $60 million for the full year. For the nine months ended September 30, 2018, we received $36.3 million in net cash proceeds from various assets divestitures.

In June 2018, we closed on certain non-core asset divestitures resulting in proceeds of approximately $6.9 million and on July 27, 2018, we closed on certain of our producing properties in the Oklahoma/Texas Panhandle for gross cash proceeds before selling costs of $17.0 million and the conveyance of $0.6 million in liabilities to the buyer. Subsequent to these divestitures, the borrowing base under our New Credit Facility was lowered by $20.0 million to $265.0 million effective July 27, 2018.

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 were augmented by derivative receipts, asset sales and debt.

As of September 30, 2018, our cash balance was $49.0 million and our New Credit Facility, which had a borrowing base of $265.0 million, was undrawn at the time. On June 29, 2018, we closed on our offering of $300 million in aggregate principle amount of 8.75% Senior Notes and used the proceeds to repay the entire outstanding balance on our New Credit Facility of $243.1 million with the remainder allocated for general corporate purposes. As of November 9, 2018, our cash balance was approximately $34.2

million with nothing drawn on our New Credit Facility. 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.

Although we did not draw on our New Credit facility during the third quarter of 2018, nor do we expect to for the remainder of the year, we anticipate drawing on the facility in early 2019. Our near term liquidity requirements are impacted by an 11 well multi pad drilling plan which we have commenced. Rather than completing each individual well as it is drilled, our plan schedules completion work only after all 11 wells are drilled and accordingly we expect these wells to begin production and thus generating revenue in spring 2019.

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 a portion of our oil, natural gas and natural gas liquids 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: Nine months ended September 30, 2018	Successor: Period from March 22, 2017 through September 30, 2017	Predecessor: Period from January 1, 2017 through March 21, 2017
Cash flows provided by operating activities	$ 96,267	$ 38,170	$ 14,385
Cash flows used in investing activities	(233,038)	(91,382)	(28,010)
Cash flows provided by (used in) financing activities	157,999	30,484	(127,732)
Net increase (decrease) in cash during the period	$ 21,228	$ (22,728)	$ (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 nine months ended September 30, 2018, of $96.3 million, increased compared to the prior year period which included $38.2 million for Successor period and of $14.4 million for the Predecessor period. The increase was primarily due to lower cash expenditures on professional fees related to our reorganization, lower cash interest paid and changes in working capital. In the meantime, reduction in operating cash flows from lower commodity sales was offset by lower cash operating expenses.

We use the net cash provided by operations to partially fund our acquisition, exploration and development activities. During 2018, we also relied on proceeds from debt issuances and cash on hand to 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 nine months ended September 30, 2018, and our budgeted 2018 capital expenditures for oil and natural gas properties are summarized in the table below. In August 2018, our Board approved an increase to our capital budget as reflected in the table below. Our capital budget was expanded to recognize working interest increases in certain wells we have recently drilled, additional leasehold acquisitions when attractive opportunities were available, cost inflation in oilfield services and the addition of a fourth drilling rig in the fourth quarter of the year.

(in thousands)	Nine months ended September 30, 2018 STACK	Other	Total	2018 Budget (1) (2) Low	High
Acquisitions (3)	107,875	—	107,875	$ 103,000	$ 108,000
Drilling	146,565	621	147,186	187,000	207,000
Enhancements	3,860	6,066	9,926	10,000	10,000
Total	258,300	6,687	264,987	$ 300,000	$ 325,000

(1) Budget categories presented include allocations of capitalized interest and general and administrative expenses.
(2) Reflects an increase to the budget approved by our Board of Directors in August 2018.
(3) Acquisitions for the nine months ended September 30, 2018 include $5.9 million in properties acquired through acreage trades, which are not included in the budget, and $7.2 million of capitalized interest.

Net cash used in investing activities during the nine months ended September 30, 2018, was comprised of cash outflows for capital expenditure of $252.7 million and payments for derivative settlements of $16.6 million partially offset by proceeds from asset divestitures of $36.3 million. Capital expenditures during the nine months ended September 30, 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 $114.4 million, cash inflows from derivative settlement receipts of $15.1 million and cash inflows from asset disposals of $7.8 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 disposals of $1.9 million.

Net cash from financing activities during the nine months ended September 30, 2018, was comprised of cash inflows from proceeds from issuing Senior Notes of $300.0 million and from borrowings on our New Credit Facility of $116.0 million partially offset by cash outflows for repayment of debt and capital leases of $245.6 million, for debt financing costs of $7.6 million and for treasury stock repurchases of $4.9 million. Cash flows from financing activities during the Successor period in 2017 was comprised primarily of proceeds from debt of $33.0 million. 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 and $50.0 million from an equity offering. The large repayments and borrowings of debt during the 2017 Predecessor period 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)	September 30, 2018	December 31, 2017
8.75% Senior Notes due 2023	$ 300,000	$ —
New Credit Facility	—	127,100
Real estate mortgage notes	8,738	9,177
Capital lease obligations	12,358	14,361
Installment note payable	371	—
Unamortized issuance costs	(12,263)	(5,979)
Total debt, net	$ 309,204	$ 144,659

Credit facilities

The New Credit Facility is a $400.0 million 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 or around May 1 and November 1 of each year. On June 29, 2018, we repaid $243.1 million representing the entire outstanding balance of the facility with proceeds from the issuance of our Senior Notes, disclosed below. Based on a borrowing base of $265.0 million, availability on the New Credit Facility as of September 30, 2018, after taking into account letters of credit on that date, was $264.2 million.

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 financial covenants as of September 30, 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.

Under the New Credit Facility, in the event of asset divestitures which occur between scheduled borrowing base redeterminations, individually or in aggregate amounting to more than 5% of the borrowing base value assigned to the disposed assets, an automatic borrowing base reduction under the Triggering Disposition clause (as defined in the New Credit Facility) would occur. In conjunction with the Triggering Disposition clause, we executed a letter agreement (the "Letter Agreement") with the lenders under our New Credit Facility. The Letter Agreement decreased the borrowing base by $20.0 million to $265.0 million following the closing of several non-core asset divestitures which included the divestiture of certain properties in the Oklahoma/Texas Panhandle, which closed on July 27, 2018, gross cash proceeds before selling costs of $17.0 million and the conveyance of $0.6 million in liabilities to the buyer (the "Marmaton Sale"), and two additional divestitures which closed in June 2018 for total proceeds of $6.9 million. The Letter Agreement, which was effective July 27, 2018, excludes the property divestitures above from future determinations of whether a Triggering Disposition has occurred. See further discussion about these divestitures in "Note 11 – Divestitures" in Item 1. Financial Statements of this report.

Our November 2018 borrowing base redetermination is currently in process.

8.75% Senior Notes

On June 29, 2018, we issued at par $300.0 million in aggregate principal amount of our Senior Notes in a private placement under Rule 144A and Regulation S of the Securities Act of 1933, as amended. The estimated offering costs were $7.3 million resulting in net proceeds of $292.7 million, which we used to repay the New Credit Facility and for general corporate purposes.

The Senior Notes bear interest at a rate of 8.75% per year beginning June 29, 2018 (payable semi-annually in arrears on January 15 and July 15 of each year, beginning on January 15, 2019) and will mature on July 15, 2023.

The Senior Notes will be the Company's senior unsecured obligations and will rank equal in right of payment with all of the Company's existing and future senior indebtedness, senior to all of the Company's existing and future subordinated indebtedness and effectively subordinated to all of the Company's existing and future secured indebtedness, to the extent of the value of the collateral securing such indebtedness.

The indenture governing our Senior Notes contains certain covenants which limit our ability to:

- incur additional indebtedness or issue certain preferred stock;
- pay dividends or repurchase or redeem capital stock;
- make certain investments;
- incur certain liens;
- enter into certain types of transactions with affiliates;
- sell assets;
- enter into agreements restricting their ability to pay dividends or make other payments;
- consolidate, merge, sell, or otherwise dispose of all or substantially all of their assets; and
- create unrestricted subsidiaries.

Upon an Event of Default (as defined in the Indenture), the Trustee or the holders of at least 25% in aggregate principal amount of the outstanding Senior Notes may declare the entire principal of, premium, if any, and accrued and unpaid interest, if any, on all the Senior Notes to be due and payable immediately.

Prior to July 15, 2020, the Company may, at its option, redeem all or, from time to time, a part of the Senior Notes at a redemption price equal to 100% of the principal amount thereof, plus an applicable make-whole premium and accrued and unpaid interest, if any, to the date of redemption. On or after July 15, 2020, the Company may, at its option, redeem all or, from time to time, a part of the Senior Notes at a redemption price equal to 100% of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest, if any, to the date of redemption.

On any one or more occasions prior to July 15, 2020, the Company, at its option, may redeem up to 35% of the aggregate principal amount of the Senior Notes with proceeds of one or more qualified equity offerings at a redemption price of 108.750% of the principal amount of the Senior Notes redeemed, plus accrued and unpaid interest, if any, and liquidated damages provided that:

(1) at least 60% of the aggregate principal amount of Senior Notes issued under the Indenture remains outstanding after each such redemption; and
(2) such redemption occurs within 180 days after the closing of any such qualified equity offering.

If the Company experiences certain kinds of changes of control, holders of the Senior Notes will be entitled to require the Company to purchase all or a portion of the Senior Notes at 101% of their principal amount, plus accrued and unpaid interest.

Our obligations under our outstanding Senior Notes have been fully and unconditionally guaranteed, on a joint and several basis, by all of our wholly owned subsidiaries.

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.

Our purchase obligations as of September 30, 2018, include contracts for four drilling rigs of which two contracts were signed in September 2018 for durations through the end of 2019. Our commitment as of September 30, 2018, on the two long term drilling rig contracts was $16.5 million. Other than the changes described herein, the issuance of Senior Notes and repayment of the New Credit Facility described in “Note 4—Debt and capital leases” in Item 1. Financial Statements of this report, there were no material changes to our contractual commitments since December 31, 2017.

Financial position

We believe that the following discussion of material changes in our balance sheet may be useful:

(in thousands)	September 30, 2018	December 31, 2017	Change
Assets			
Total oil and natural gas properties	1,149,569	992,353	157,216
Liabilities			
Accounts payable and accrued liabilities	66,614	75,414	(8,800)
Revenue distribution payable	28,470	17,966	10,504
Asset retirement obligations	25,839	35,990	(10,151)
Long-term debt and capital leases	309,204	144,659	164,545
Derivative instruments	68,947	13,126	55,821

- The increase to oil and natural gas properties was primarily due to our capital expenditures in the current year partially offset by depreciation.
- Accounts payable and accrued liabilities decreased primarily as a result of reduced capital activity under our JDA in the third quarter.
- Revenue distribution payable increased primarily due to revenue from wells for which ownership interests are in the process of being finalized and hence not been distributed.
- Asset retirement obligation decreased primarily due to divestitures of non-core assets during the year.
- Long-term debt was higher in total due to additional drawings on our New Credit Facility, increasing the outstanding amount from $127.1 million at the end of 2017 to $243.1 million in June 2018 whereupon we issued $300.0 million in Senior Notes and utilized part of the proceeds to repay the entire balance on the New Credit Facility. The additional debt incurred during the year was primarily utilized for capital expenditures and for general corporate purposes.
- Our 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:

	Successor				Predecessor
(in thousands)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Period from March 22, 2017 through September 30, 2017	Period from January 1, 2017 through March 21, 2017
Net (loss) income	(12,068)	(19,115)	(45,503)	(17,433)	1,041,959
Interest expense	4,205	5,283	7,315	10,984	5,862
Income tax expense	—	37	—	75	37
Depreciation, depletion, and amortization	22,252	32,167	63,765	66,432	24,915
Non-cash change in fair value of derivative instruments	16,804	22,236	55,822	19,232	(46,721)
Impact of derivative repricing	(1,698)	—	(3,950)	—	—
Loss (gain) on settlement of liabilities subject to compromise	—	—	48	—	(372,093)
Fresh start accounting adjustments	—	—	—	—	(641,684)
Interest income	(7)	(4)	(9)	(9)	(133)
Stock-based compensation expense	2,304	2,776	8,598	2,776	155
(Gain) loss on sale of assets	2,024	13	2,599	876	(206)
Write-off of debt issuance costs, discount and premium	—	—	—	—	1,687
Restructuring, reorganization and other	493	892	1,962	2,703	24,297
Adjusted EBITDA	$ 34,309	$ 44,285	$ 90,647	$ 85,636	$ 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)		September 30, 2018		December 31, 2017
Current assets per GAAP	$	122,826	$	95,894
Plus—Availability under New Credit Facility		264,172		157,072
Current assets as adjusted	$	386,998	$	252,966
Current liabilities per GAAP		143,805		117,075
Less—Current derivative instruments		(29,905)		(8,959)
Less—Current asset retirement obligation		(1,481)		(2,774)
Less—Current maturities of long term debt		(3,444)		(3,273)
Current liabilities as adjusted	$	108,975	$	102,069
Current ratio per GAAP		0.85		0.82
Current ratio for loan compliance		3.55		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 nine months ended September 30, 2018, our gross revenues from oil and natural gas sales would change approximately $3.4 million for each $1.00 change in oil and natural gas liquid prices and $1.2 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 September 30, 2018, was a net liability of $68.9 million. Based on our outstanding derivative instruments as of September 30, 2018, summarized below, a 10% increase in the September 30, 2018, forward curves used to mark-to-market our derivative instruments would have increased our net liability position to $105.7 million, while a 10% decrease would have reduced our net liability position to $36.8 million.

Our outstanding oil derivative instruments as of September 30, 2018, are summarized below:

		Weighted average fixed price per Bbl		
Period and type of contract	Volume MBbls	Swaps	Purchased puts	Sold calls
October - December 2018				
Oil swaps	515	$ 58.21	$ —	$ —
Oil collars	46	$ —	$ 50.00	$ 60.50
Oil roll swaps	150	$ 0.59	$ —	$ —
January - March 2019				
Oil swaps	391	$ 55.79	$ —	$ —
Oil roll swaps	150	$ 0.59	$ —	$ —
April - June 2019				
Oil swaps	413	$ 56.17	$ —	$ —
Oil roll swaps	140	$ 0.55	$ —	$ —
July - September 2019				
Oil swaps	372	$ 55.66	$ —	$ —
Oil roll swaps	120	$ 0.46	$ —	$ —
October - December 2019				
Oil swaps	386	$ 55.96	$ —	$ —
Oil roll swaps	120	$ 0.46	$ —	$ —
January - March 2020				
Oil swaps	394	$ 49.59	$ —	$ —
Oil roll swaps	120	$ 0.46	$ —	$ —
April - June 2020				
Oil swaps	357	$ 49.42	$ —	$ —
Oil roll swaps	110	$ 0.42	$ —	$ —
July - September 2020				
Oil swaps	375	$ 49.46	$ —	$ —
Oil roll swaps	90	$ 0.30	$ —	$ —
October - December 2020				
Oil swaps	422	$ 49.68	$ —	$ —
Oil roll swaps	90	$ 0.30	$ —	$ —
January - March 2021				
Oil swaps	134	$ 44.34	$ —	$ —
Oil roll swaps	90	$ 0.30	$ —	$ —
April - June 2021				
Oil swaps	135	$ 44.34	$ —	$ —
Oil roll swaps	60	$ 0.30	$ —	$ —
July - September 2021				
Oil swaps	136	$ 44.34	$ —	$ —
October - December 2021				
Oil swaps	138	$ 44.34	$ —	$ —

Our outstanding natural gas derivative instruments as of September 30, 2018, are summarized below:

Period and type of contract	Volume BBtu	Weighted average fixed price per MMBtu
October - December 2018		
Natural gas swaps	2,519	$2.88
Natural gas basis swaps	1,500	$0.70
January - March 2019		
Natural gas swaps	1,889	$2.80
Natural gas basis swaps	1,500	$0.70
April - June 2019		
Natural gas swaps	1,878	$2.80
Natural gas basis swaps	1,000	$0.70
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

Our outstanding natural gas liquid derivative instruments as of September 30, 2018 are summarized below:

Period and type of contract	Volume Gallons	Weighted average fixed price per gallon
October - December 2018		
Natural gasoline swaps	1,512	$1.55
Propane swaps	3,528	$0.88
January - March 2019		
Natural gasoline swaps	1,386	$1.39
Propane swaps	3,234	$0.74
April - June 2019		
Natural gasoline swaps	1,302	$1.39
Propane swaps	2,940	$0.74
July - September 2019		
Natural gasoline swaps	1,134	$1.39
Propane swaps	2,604	$0.74
October - December 2019		
Natural gasoline swaps	1,134	$1.39
Propane swaps	2,688	$0.74
January - March 2020		
Natural gasoline swaps	1,134	$1.39
Propane swaps	2,604	$0.74
April - June 2020		
Natural gasoline swaps	756	$1.39
Propane swaps	1,680	$0.74

In October and November 2018, we entered into several derivative contracts with varying maturities outlined below:

		Weighted average fixed price per Bbl
Period and type of contract	**Volume MBbls**	**Swaps**
2019		
Oil swaps	220	$ 63.51
2020		
Oil swaps	100	$ 61.64

Period and type of contract	Volume BBtu	Weighted average fixed price per MMBtu
2018		
Natural gas basis swaps	681	$ (0.52)
2019		
Natural gas basis swaps	2,481	$ (0.66)
Natural gas swaps	660	$ 2.89

Interest rates. At September 30, 2018, our New Credit Facility was undrawn. Borrowings on the New Credit Facility are subject to market rates of interest as determined from time to time by the banks. As of June 28, 2018, immediately prior to the closing of the Senior Notes, interest on the $243.1 million in borrowings were calculated at the Adjusted LIBO Rate, as defined under the New Credit Facility and repayment of the entire balance of the New Credit Facility, plus the applicable margin, which resulted in a weighted average interest rate of 5.31% 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 $265.0 million, equal to our borrowing base at September 30, 2018, the cash flow impact for a 12-month period resulting from a 100 basis point change in interest rates would be $2.6 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 September 30, 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. We may make changes in our internal control procedures from time to time.

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

Security holders and potential investors in our securities should carefully consider the risk factors set forth below and in our Annual Report on Form 10-K filed with the SEC on March 28, 2018, together with the information set forth in our subsequent Quarterly Reports on Form 10-Q, current reports on Form 8-K and other materials we file with the SEC.

Other than set forth below, there have been no material changes to the Risk Factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017, or our subsequent quarterly reports on Form 10-Q.

Multi-well pad drilling and project development may result in volatility in our operating results

We have commenced drilling multi-well spacing test patterns in our STACK play. These projects, which are capital intensive, involve horizontal multi-well pad drilling, tighter drill spacing and completions techniques that evolve over time as learnings are captured and applied. The use of this technique may increase the risk of unintentional communication with other adjacent wells and the potential to reduce total recoverable reserves from the reservoir. Problems affecting a single well could adversely affect production from all of the wells on the pad or in the entire project. Furthermore, additional time is required to drill and complete multiple wells before any such wells begin producing. As a result, multi-well pad drilling and project development can cause delays in the scheduled commencement of production or interruptions in ongoing production. These delays or interruptions may cause declines or volatility in our operating results due to timing. Any of these factors could reduce our revenues and could result in a material adverse effect on our financial condition or results of operations.

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

None.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

Exhibit No.	Description
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).
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).
4.5*	Indenture dated June 29, 2018, among the Company, the Guarantors party thereto, and UMB Bank, N.A., as Trustee (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K filed on July 2, 2018).
4.6*	Form of 8.750% Senior Note due 2023 (Incorporated by reference to Exhibit A of Exhibit 4.1 of the Company's Current Report on Form 8-K filed on July 2, 2018).
10.1*	Support Agreement, dated August 8, 2018 by and among Chaparral Energy, Inc., Contrarian Capital Management, L.L.C. and certain funds and accounts managed by Contrarian Capital Management, L.L.C. and its affiliates (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 10-Q filed on August 13, 2018).
10.2	Letter Agreement, effective as of July 27, 2018, by and among Chaparral Energy, Inc., each Guarantor party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and each of the Lenders party thereto.
31.1	Certification by Principal Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act.

Exhibit No.	Description
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 SEC 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: November 13, 2018

EXHIBIT 10.2

JPMORGAN CHASE BANK, N.A.
712 Main Street – 12 South
Houston, Texas 77002

July 27, 2018

Chaparral Energy, Inc.
701 Cedar Lake Blvd.
Oklahoma City, Oklahoma 73114

Attention: Joe Evans

Re: Letter Agreement Regarding Marmaton Sale

Ladies and Gentlemen:

Reference is hereby made to that certain Tenth Restated Credit Agreement dated as of December 21, 2017 (as amended prior to the date hereof, the "Credit Agreement"), among Chaparral Energy, Inc., a Delaware corporation (the "Borrower"), each of the Lenders from time to time party thereto, JPMorgan Chase Bank, N.A., as administrative agent (the "Administrative Agent") and the other parties party thereto. Capitalized terms used herein without definition shall have the meanings given to them in the Credit Agreement.

1. Marmaton Sale. The Borrower has advised the Administrative Agent and the Lenders that one of the Subsidiaries of the Borrower intends to sell or otherwise transfer those certain Oil and Gas Properties more particularly described in that certain Purchase and Sale Agreement, dated as of June 20, 2018, among Chaparral Energy, L.L.C., an Oklahoma limited liability company ("Chaparral") and Resource Oil & Gas, L.L.C., an Oklahoma limited liability company (such version of such purchase and sale agreement, the "Marmaton Sale Agreement", such Oil and Gas Properties including the oil and gas leases and wells described on Exhibit A to the Marmaton Sale Agreement, together with the other "Properties" as defined in the Marmaton Sale Agreement, the "Marmaton Properties", and such sale, the "Marmaton Sale"). The Borrower has further advised the Administrative Agent and the Lenders that the consummation of the Marmaton Sale will trigger an automatic reduction of the Borrowing Base pursuant to Section 2.07(f) of the Credit Agreement. The Borrower has requested that the Lenders disregard (a) the Marmaton Sale, (b) the sale of certain Oil and Gas Properties more particularly described in that certain Purchase and Sale Agreement, dated as of May 24, 2018, among Chaparral and DPMS Oil, LLC, a Delaware limited liability company (such agreement, the "DPMS Sale Agreement", such Oil and Gas Properties including the oil and gas leases and wells described on Exhibit A to the DPMS Sale Agreement, together with the other "Properties" as defined in the DPMS Sale Agreement, the "DPMS Properties", and such sale, the "DPMS Sale") and (c) the sale of certain Oil and Gas Properties more particularly described in that certain Purchase and Sale Agreement, dated as of May 10, 2018, among Chaparral and PO&G Resources Fund, LP, a Delaware limited partnership (such agreement, the "PO&G Sale Agreement", such Oil and Gas Properties including the oil and gas leases and wells described on Exhibit A to the PO&G Sale Agreement, together with the other "Properties" as defined in the PO&G Sale Agreement, the "PO&G Properties", and such sale, the "PO&G Sale"), in future determinations of whether a Triggering Disposition has occurred.

2. Purposes of this Letter. The Borrower, the Administrative Agent and the Lenders party hereto desire to enter into this Letter Agreement (this "Letter Agreement") to evidence such Lenders' (a) approval of the amount of the Borrowing Base reduction following the consummation of the Marmaton Sale, and (b) consent to disregard the Marmaton Sale, the DPMS Sale and the PO&G Sale in future determinations of whether a Triggering Disposition has occurred, in each case, on the terms and conditions set forth herein.

3. Borrowing Base Reduction. In reliance on the representations, warranties, covenants and agreements contained in this Letter Agreement, and subject to the terms and conditions set forth in this Section 3 and subject to the conditions precedent set forth in Section 4, the Lenders party hereto hereby agree that (a) pursuant to Section 2.07(f) of the Credit Agreement, upon the consummation of the Marmaton Sale, the Borrowing Base shall be automatically reduced, without any further action required on the part of the Administrative Agent or the Lenders, on the date that the Marmaton Sale is consummated by an amount equal to $20,000,000, and (b) so long as the reduction in the Borrowing Base provided for in the foregoing clause (a) occurs, the Borrowing Base value of the Marmaton Properties, the DPMS Properties and the PO&G Properties shall be disregarded for future calculations of the aggregate Borrowing Base value of Oil and Gas Properties sold or otherwise disposed of during any period for purposes of determining whether a Triggering Disposition has occurred; *provided*, that each of the following conditions is satisfied:

(i) The Marmaton Sale shall be consummated on or prior to August 31, 2018;
(ii) The Marmaton Sale shall be consummated in accordance with the Marmaton Sale Agreement in all material respects and no term or condition of the Marmaton Sale Agreement shall have been amended, modified or waived in a manner adverse to the Administrative Agent or the Lenders in any material respect; *provided* that, for the avoidance of doubt, any amendment, modification or waiver that results in the addition of any property to the Marmaton Properties to be sold by a Credit Party pursuant to the Marmaton Sale Agreement shall be deemed to be adverse to the Administrative Agent and the Lenders in a material respect; and
(iii) The Administrative Agent shall have received final, executed copies of the Marmaton Sale Agreement (including all amendments thereto, if any) and all other material agreements, assignments or other conveyance documents executed in connection therewith, which copies shall be certified as being true and correct in all material respects by a Responsible Officer of the Borrower.

Notwithstanding anything to the contrary contained in this Letter Agreement, the agreements set forth herein are limited solely to the matters set forth above, and nothing contained in this Letter Agreement shall be deemed a consent to, or waiver of, any other action or inaction of the Borrower or any other Credit Party which constitutes (or would constitute) a violation of any provision of the Credit Agreement or any other Loan Document. Neither the Lenders nor the Administrative Agent shall be obligated to grant any future waivers, consents or amendments with respect to any other provision of the Credit Agreement or any other Loan Document.

4. Conditions Precedent. The agreements contained in Section 3 hereof shall be effective when each of the following conditions precedent is satisfied (or waived in accordance with Section 12.02 of the Credit Agreement):

4.1 Counterparts. The Administrative Agent shall have received from the Required Lenders, the Borrower, and each Guarantor counterparts (in such number as may be reasonably requested by the Administrative Agent) of this Letter Agreement signed on behalf of such Persons.

4.2 Fees and Expenses. In consideration for the agreements set forth herein, the Borrower shall have paid to the Administrative Agent any and all reasonable and documented out-of-pocket fees and expenses payable to the Administrative Agent pursuant to or in connection with the this Letter Agreement (to the extent invoiced and required to be paid or reimbursed by the Borrower in accordance with Section 12.03 of the Credit Agreement) on or before the date hereof.

5. Miscellaneous.

5.1 Confirmation. The provisions of the Credit Agreement, as modified by this Letter Agreement, shall remain in full force and effect following the effectiveness of this Letter Agreement.

5.2 Ratification and Affirmation; Representations and Warranties. Each of the Borrower and each Guarantor hereby (a) ratifies and affirms its respective obligations under, and acknowledges and renews its respective continued liability under, each Loan Document to which it is a party and agrees that each Loan Document to which it is a party, as the same may be amended hereby, remains in full force and effect, except as expressly amended hereby, and (b) represents and warrants to the Lenders that, as of the date hereof: (i) all of the representations and warranties contained in each Loan Document to which it is a party are true and correct in all material respects, except (A) to the extent any such representations and warranties are expressly limited to an earlier date, such representations and warranties continue to be true and correct in all material respects as of such specified earlier date, and (B) to the extent that any such representation and warranty is expressly qualified by materiality or by reference to Material Adverse Effect, such representation and warranty (as so qualified) is true and correct in all respects, and (ii) no Default or Event of Default has occurred and is continuing.

5.3 Loan Document. This Letter Agreement is a "Loan Document" as defined and described in the Credit Agreement and all of the terms and provisions of the Credit Agreement relating to Loan Documents shall apply hereto.

5.4 Counterparts. This Letter Agreement may be executed by one or more of the parties hereto in any number of separate counterparts, and all of such counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of this Letter Agreement by facsimile transmission (including electronic transmission via scanned .pdf) shall be effective as delivery of a manually executed counterpart hereof.

5.5 NO ORAL AGREEMENT. THE CREDIT AGREEMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT AMONG THE PARTIES HERETO AND THERETO 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 GOVERNING LAW. THIS LETTER AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.

5.7 Payment of Expenses. The Borrower agrees to pay or reimburse the Administrative Agent for all of its reasonable and documented out-of-pocket costs and expenses incurred in connection with this Letter Agreement, any other documents prepared in connection herewith and the transactions contemplated hereby, including, without limitation, the reasonable fees and disbursements of counsel to the Administrative Agent, as and when required by Section 12.03 of the Credit Agreement.

5.8 Severability. Any provision of this Letter Agreement which is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

5.9 Successors and Assigns. This Letter Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and permitted assigns.

[Signature Pages Follow]

IN WITNESS WHEREOF, the parties hereto have caused this Letter Agreement to be duly executed as of the date first written above.

Borrower:	**CHAPARRAL ENERGY, INC.**, an Delaware corporation **By:** /s/ Linda Byford **Name**: Linda Byford **Title:** Associate Vice President - Legal
Guarantors:	**CHAPARRAL ENERGY, L.L.C.**, an Oklahoma limited liability company **CHAPARRAL RESOURCES, L.L.C.**, an Oklahoma limited liability company **CHAPARRAL CO2, 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** **By:** /s/ Linda Byford **Name**: Linda Byford **Title:** Associate Vice President - Legal

Administrative Agent and 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/ Michael Higgins Name: Michael Higgins Title: Managing Director
Lender:	**NATIXIS, NEW YORK BRANCH** By: /s/ Leila Zomorrodian Name: Leila Zomorrodian Title: Director By: /s/ Vikram Nath Name: Vikram Nath Title: Director
Lender:	**KEYBANK NATIONAL ASSOCIATION** By: /s/ David M. Bornstein Name: David M. Bornstein Title: Senior Vice President
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/ Donovan C. Broussard
Name: Donovan C. Broussard
Title: Authorized Signatory

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

Lender: **CITIBANK, N.A.**

By: /s/ Ryan Watson
Name: Ryan Watson
Title: Senior Vice President

Lender: **COMPASS BANK**

By: /s/ Kari McDaniel
Name: Kari McDaniel
Title: Vice President

Lender: **CREDIT AGRICOLE CORPORATE AND INVESTMENT BANK**

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

By: /s/ David Gurghigian
Name: David Gurghigian
Title: Managing Director

Lender: **FIFTH THIRD BANK**

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

Lender: **THE HUNTINGTON NATIONAL BANK**

By: /s/ Jason A. Zilewicz
Name: Jason A. Zilewicz
Title: Director

Lender: **ROYAL BANK OF CANADA**

By: /s/ Emilee Scott
Name: Emilee Scott
Title: Authorized Signatory

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

By: /s/ Annie Doval
Name: Annie Doval
Title: Authorized Signatory

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

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

Lender: **COMERICA BANK**

By: /s/ Jeffrey M. LaBauve
Name: Jeffrey M. LaBauve
Title: Vice President

Lender: **EAST WEST BANK**

By: /s/ Reed V. Thompson
Name: Reed V. Thompson
Title: Senior Vice President

Lender: **TEXAS CAPITAL BANK, NATIONAL ASSOCIATION**

By: /s/ Gabnera Ramirez
Name: Gabnera Ramirez
Title: Authorized Officer

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):
6. 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
7. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 13, 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):
6. 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
7. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 13, 2018

/s/ Joseph O. Evans

Joseph O. Evans

Chief Financial Officer and Executive Vice President

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 September 30, 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: November 13, 2018

/s/ K. Earl Reynolds

K. Earl Reynolds

Chief Executive Officer

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 period ended September 30, 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: November 13, 2018

/s/ Joseph O. Evans

Joseph O. Evans
Chief Financial Officer and Executive Vice President