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

FORM 10-Q

(X) Quarterly Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2017
Commission File Number 1-8754

SILVERBOW RESOURCES, INC.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**20-3940661**
(State of Incorporation)	*(I.R.S. Employer Identification No.)*

575 North Dairy Ashford, Suite 1200
Houston, Texas 77079
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

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, and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See definition 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 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 ☐

Indicate the number of shares outstanding of each of the Issuer's classes of common stock, as of the latest practicable date.

Common Stock ($.01 Par Value) (Class of Stock)	11,551,468 Shares outstanding at November 1, 2017

Explanatory Note

SilverBow Resources, Inc. was formerly known as Swift Energy Company. On May 5, 2017, through an amendment to its Certificate of Incorporation and Bylaws, Swift Energy Company changed its name to SilverBow Resources, Inc. Additionally, SilverBow Resources, Inc began trading on the New York Stock Exchange ("NYSE") under the symbol "SBOW" on May 5, 2017.

SILVERBOW RESOURCES, INC.

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2017
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Condensed Consolidated Balance Sheets (Unaudited)
SilverBow Resources, Inc. and Subsidiaries (in thousands, except share amounts)

	Successor	
	September 30, 2017 (Unaudited)	December 31, 2016
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 12,861	$ 303
Accounts receivable, net	22,222	17,490
Other current assets	5,155	3,686
Total Current Assets	40,238	21,479
Property and Equipment:		
Property and Equipment, full cost method, including $52,075 and $33,354 of unproved property costs not being amortized at the end of each period	668,398	517,074
Less – Accumulated depreciation, depletion, amortization & impairment	(202,211)	(169,879)
Property and Equipment, Net	466,187	347,195
Other Long-Term Assets	9,905	8,625
Total Assets	$ 516,330	$ 377,299
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 41,998	$ 56,257
Accrued capital costs	19,721	11,954
Accrued interest	1,635	1,721
Undistributed oil and gas revenues	10,249	9,192
Total Current Liabilities	73,603	79,124
Long-Term Debt	250,000	198,000
Asset Retirement Obligations	24,174	22,291
Other Long-Term Liabilities	2,431	1,829
Commitments and Contingencies (Note 10)		
Stockholders' Equity:		
Preferred stock, $.01 par value, 10,000,000 shares authorized, none issued	—	—
Common stock, $.01 par value, 40,000,000 shares authorized, 11,595,020 and 10,076,059 shares issued and 11,551,468 and 10,053,574 shares outstanding, respectively	116	101
Additional paid-in capital	276,753	232,917
Treasury stock, held at cost, 43,552 and 22,485 shares	(1,293)	(675)
Accumulated deficit	(109,454)	(156,288)
Total Stockholders' Equity	166,122	76,055
Total Liabilities and Stockholders' Equity	$ 516,330	$ 377,299

See accompanying Notes to Condensed Consolidated Financial Statements.

Condensed Consolidated Statements of Operations (Unaudited)
SilverBow Resources, Inc. and Subsidiaries (in thousands, except per-share amounts)

	Successor	
	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016
Revenues:		
Oil and gas sales	$ 49,019	$ 47,959
Operating Expenses:		
General and administrative, net	6,031	11,691
Depreciation, depletion, and amortization	11,832	13,287
Accretion of asset retirement obligations	582	1,099
Lease operating costs	5,831	9,481
Transportation and gas processing	4,921	4,883
Severance and other taxes	2,479	2,683
Total Operating Expenses	31,676	43,124
Operating Income (Loss)	17,343	4,835
Non-Operating Income (Expense)		
Net gain (loss) on commodity derivatives	(1,603)	2,603
Interest expense, net	(2,868)	(5,880)
Reorganization items, net	—	(1,193)
Other income (expense), net	12	29
Income (Loss) Before Income Taxes	12,884	394
Provision (Benefit) for Income Taxes	—	—
Net Income (Loss)	$ 12,884	$ 394
Per Share Amounts-		
Basic: Net Income (Loss)	$ 1.12	$ 0.04
Diluted: Net Income (Loss)	$ 1.12	$ 0.04
Weighted Average Shares Outstanding - Basic	11,531	10,000
Weighted Average Shares Outstanding - Diluted	11,545	10,361

See accompanying Notes to Condensed Consolidated Financial Statements.

Condensed Consolidated Statements of Operations (Unaudited)
SilverBow Resources, Inc. and Subsidiaries (in thousands, except per-share amounts)

	Successor		Predecessor
	Nine Months Ended September 30, 2017	Period from April 23, 2016 through September 30, 2016	Period from January 1, 2016 through April 22, 2016
Revenues:			
Oil and gas sales	$ 137,216	$ 78,540	$ 43,027
Operating Expenses:			
General and administrative, net	22,676	15,919	9,245
Depreciation, depletion, and amortization	32,375	26,621	20,439
Accretion of asset retirement obligations	1,722	1,931	1,610
Lease operating costs	16,380	17,262	14,933
Transportation and gas processing	14,067	9,069	6,090
Severance and other taxes	6,377	4,547	3,917
Write-down of oil and gas properties	—	133,496	77,732
Total Operating Expenses	93,597	208,845	133,966
Operating Income (Loss)	43,619	(130,305)	(90,939)
Non-Operating Income (Expense)			
Net gain (loss) on commodity derivatives	14,465	(7,308)	—
Interest expense, net	(11,117)	(10,137)	(13,347)
Reorganization items, net	—	(1,469)	956,142
Other income (expense), net	(133)	12	(245)
Income (Loss) Before Income Taxes	46,834	(149,207)	851,611
Provision (Benefit) for Income Taxes	—	—	—
Net Income (Loss)	$ 46,834	$ (149,207)	$ 851,611
Per Share Amounts-			
Basic: Net Income (Loss)	$ 4.10	$ (14.92)	$ 19.06
Diluted: Net Income (Loss)	$ 4.08	$ (14.92)	$ 18.64
Weighted Average Shares Outstanding - Basic	11,417	10,000	44,692
Weighted Average Shares Outstanding - Diluted	11,479	10,000	45,697

See accompanying Notes to Condensed Consolidated Financial Statements.

Condensed Consolidated Statements of Stockholders' Equity (Unaudited)

SilverBow Resources, Inc. and Subsidiaries (in thousands, except share amounts)

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total
Balance, December 31, 2015 (Predecessor)	$ 448	$ 776,358	$ (2,491)	$ (1,627,039)	$ (852,724)
Purchase of treasury shares (65,170 shares)	—	—	(5)	—	(5)
Issuance of restricted stock (229,690 shares)	2	(2)	—	—	—
Share-based compensation	—	1,118	—	—	1,118
Net Income	—	—	—	851,611	851,611
Balance, April 22, 2016 (Predecessor)	$ 450	$ 777,474	$ (2,496)	$ (775,428)	$ —
Cancellation of Predecessor equity	$ (450)	$ (777,474)	$ 2,496	$ 775,428	$ —
Balance, April 22, 2016 (Predecessor)	$ —	$ —	$ —	$ —	$ —
Issuance of Successor common stock & warrants	$ 100	$ 229,299	$ —	$ —	$ 229,399
Balance, April 22, 2016 (Successor)	$ 100	$ 229,299	$ —	$ —	$ 229,399
Purchase of treasury shares (22,485 shares)	—	—	(675)	—	(675)
Issuance of restricted stock (76,058 shares)	1	—	—	—	1
Share-based compensation	—	3,618	—	—	3,618
Net Loss	—	—	—	(156,288)	(156,288)
Balance, December 31, 2016 (Successor)	$ 101	$ 232,917	$ (675)	$ (156,288)	$ 76,055
Purchase of treasury shares (21,067 shares)	—	—	(618)	—	(618)
Issuance common stock (1,403,508 shares)	14	39,166	—	—	39,180
Issuance of restricted stock (115,453 shares)	1	(1)	—	—	—
Share-based compensation	—	4,671	—	—	4,671
Net Income	—	—	—	46,834	46,834
Balance, September 30, 2017 (Successor)	$ 116	$ 276,753	$ (1,293)	$ (109,454)	$ 166,122

See accompanying Notes to Condensed Consolidated Financial Statements.

Condensed Consolidated Statements of Cash Flows (Unaudited)
SilverBow Resources, Inc. and Subsidiaries (in thousands)

	Successor		Predecessor
	Nine Months Ended September 30, 2017	Period from April 23, 2016 through September 30, 2016	Period from January 1, 2016 through April 22, 2016
Cash Flows from Operating Activities:			
Net income (loss)	$ 46,834	$ (149,207)	$ 851,611
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities-			
Depreciation, depletion, and amortization	32,375	26,621	20,439
Write-down of oil and gas properties	—	133,496	77,732
Accretion of asset retirement obligations	1,722	1,931	1,610
Share-based compensation expense	4,538	3,132	886
Loss (gain) on derivatives	(14,465)	7,308	—
Cash settlements on derivatives	(2,503)	(1,100)	—
Settlements of asset retirement obligations	(2,245)	(1,919)	(848)
Write-down of debt issuance cost	2,401	—	—
Reorganization items (non-cash)	—	—	(977,696)
Other	760	1,721	229
Change in operating assets and liabilities-			
(Increase) decrease in accounts receivable and other current assets	(3,884)	14,669	(5,474)
Increase (decrease) in accounts payable and accrued liabilities	1,605	(8,283)	(9,647)
Increase (decrease) in accrued interest	(86)	1,041	(308)
Net Cash Provided by (Used in) Operating Activities	67,052	29,410	(41,466)
Cash Flows from Investing Activities:			
Additions to property and equipment	(141,636)	(36,794)	(24,530)
Proceeds from the sale of property and equipment	653	594	48,661
Net Cash Provided by (Used in) Investing Activities	(140,983)	(36,200)	24,131
Cash Flows from Financing Activities:			
Proceeds from bank borrowings	349,000	49,000	328,000
Payments of bank borrowings	(297,000)	(48,000)	(324,900)
Net proceeds from issuances of common stock	39,180	—	—
Purchase of treasury shares	(618)	—	(4)
Payments of debt issuance costs	(4,073)	(502)	(6,482)
Net Cash Provided by (Used in) Financing Activities	86,489	498	(3,386)
Net increase (decrease) in Cash and Cash Equivalents	12,558	(6,292)	(20,721)
Cash and Cash Equivalents at Beginning of Period	303	8,739	29,460
Cash and Cash Equivalents at End of Period	$ 12,861	$ 2,447	$ 8,739
Supplemental Disclosures of Cash Flow Information:			
Cash paid during period for interest, net of amounts capitalized	$ 11,390	$ 8,021	$ 10,367
Cash paid for reorganization items	$ —	$ 12,017	$ 15,643
Changes in capital accounts payable and capital accruals	$ 9,375	$ (17,554)	$ 1,843

See accompanying Notes to Condensed Consolidated Financial Statements.

Notes to Condensed Consolidated Financial Statements (Unaudited)
SilverBow Resources, Inc. and Subsidiaries

(1) General Information

SilverBow Resources, Inc. ("SilverBow," the "Company," or "we") is a growth oriented independent oil and gas company headquartered in Houston, Texas. The Company's strategy is focused on acquiring and developing assets in the Eagle Ford Shale located in South Texas. Being a committed and long-term operator in South Texas, the Company possesses a significant understanding of the reservoirs in the region. We leverage this competitive understanding to assemble high quality drilling inventory while continuously enhancing our operations to maximize returns on capital invested.

The condensed consolidated financial statements included herein are unaudited and have been prepared by the Company and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, and are in the opinion of our management necessary for a fair presentation. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States ("GAAP") have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission. We believe that the disclosures presented are adequate to allow the information presented not to be misleading. The condensed consolidated financial statements should be read in conjunction with the audited financial statements and the notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016 as filed with the Securities and Exchange Commission on February 27, 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.

(2) Summary of Significant Accounting Policies

Fresh Start Accounting. Upon emergence from bankruptcy on April 22, 2016, the Company adopted Fresh Start Accounting. As a result of the application of fresh start accounting, as well as the effects of the implementation of the joint plan of reorganization (the "Plan"), the Consolidated Financial Statements on or after April 22, 2016, are not comparable with the Consolidated Financial Statements prior to that date. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to April 22, 2016. References to "Predecessor" or "Predecessor Company" refer to the financial position and results of operations of the Company prior to April 22, 2016. See Note 12 of the condensed consolidated financial statements for further details.

Basis of Presentation. The consolidated financial statements included herein have been prepared by SilverBow, and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, and are in the opinion of our management necessary for a fair presentation.

Principles of Consolidation. The accompanying condensed consolidated financial statements include the accounts of SilverBow and its wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and gas properties, with a focus on oil and natural gas reserves in the Eagle Ford trend in Texas. Our undivided interests in oil and gas properties are accounted for using the proportionate consolidation method, whereby our proportionate share of the assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying condensed consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying condensed consolidated financial statements.

Subsequent Events. We have evaluated subsequent events requiring potential accrual or disclosure in our condensed consolidated financial statements. On November 6, 2017, the Company announced the appointment of the Company's new Chief Operating Officer, Steven Adam. On November 6, 2017, Company also announced that Robert J. Banks, Executive Vice President and Chief Operating Officer was separating from the Company to pursue other endeavors, effective November 2, 2017. The former Chief Operating Officer will receive severance benefits, which include cash payments, accelerated vesting of his share-based compensation, and other benefits in accordance with his Third Amended and Restated Employment Agreement. There were no other material subsequent events requiring additional disclosure in these condensed consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. Such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates and assumptions underlying these financial statements include:

- the estimates of reorganization value, enterprise value and fair value of assets and liabilities upon emergence from bankruptcy and application of fresh start accounting,
- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, the related present value of estimated future net cash flows there-from, and the ceiling test impairment calculation,
- estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas sales, capital expenditures and lease operating expenses,
- estimates in the calculation of share-based compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations,
- estimates in the calculation of the fair value of commodity derivative assets and liabilities,
- estimates in the assessment of current litigation claims against the Company, and
- estimates in amounts due with respect to open state regulatory audits.

While we are not currently aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as new accounting pronouncements, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which relate to prior periods. These types of adjustments cannot be currently estimated and are expected to be recorded in the period during which the adjustments are known.

We are subject to legal proceedings, claims, liabilities and environmental matters that arise in the ordinary course of business. We accrue for losses when such losses are considered probable and the amounts can be reasonably estimated.

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), such internal costs capitalized totaled $1.3 million and $2.0 million, respectively. For the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), such internal costs capitalized totaled $3.6 million, $2.9 million and $3.5 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties (refer to Note 5 of these condensed consolidated financial statements for further discussion on capitalized interest costs).

The "Property and Equipment" balances on the accompanying condensed consolidated balance sheets are summarized for presentation purposes. The following is a detailed breakout of our "Property and Equipment" balances (in thousands):

	September 30, 2017	December 31, 2016
Property and Equipment		
Proved oil and gas properties	$ 613,207	$ 480,499
Unproved oil and gas properties	52,075	33,354
Furniture, fixtures, and other equipment	3,116	3,221
Less – Accumulated depreciation, depletion, amortization & impairment	(202,211)	(169,879)
Property and Equipment, Net	$ 466,187	$ 347,195

No gains or losses are recognized upon the sale or disposition of oil and natural gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and natural gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a cost center. Internal costs associated with selling properties are expensed as incurred.

We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties-including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties-by an overall rate determined by dividing the physical units of oil and natural gas produced (which excludes natural gas consumed in operations) during the period by the total estimated units of proved oil and natural gas reserves (which excludes natural gas consumed in operations) at the beginning of the period. Future development costs are estimated on a property-by-property basis based on current economic conditions. The period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment are recorded at cost and are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between two and 20 years. Repairs and maintenance are charged to expense as incurred.

Geological and geophysical ("G&G") costs incurred on developed properties are recorded in "Proved properties" and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in "Unproved properties" and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, economic conditions, capital availability, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test").

The quarterly calculations of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, for the period of January 1, 2016 through April 22, 2016 (predecessor), we reported a non-cash impairment write-down, on a before-tax basis, of $77.7 million on our oil and natural gas properties. Primarily due to pricing differences between the 12-month average oil and gas prices used in the Ceiling Test and the forward strip prices used to estimate the initial fair value of oil and gas properties on the Company's April 22, 2016 (successor) balance sheet, we incurred a non-cash impairment write-down for the period of April 23, 2016 through September 30, 2016 (successor) of $133.5 million. There was no write-down for the three and nine months ended September 30, 2017 (successor).

If future capital expenditures outpace future discounted net cash flows in our reserve calculations, if we have significant declines in our oil and natural gas reserves volumes (which also reduces our estimate of discounted future net cash flows from proved oil and natural gas reserves) or if oil or natural gas prices decline, it is likely that non-cash write-downs of our oil and natural gas properties will occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties due to decreases in oil or natural gas prices.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. The Company uses the entitlement method of accounting for gas imbalances in which we recognize our ownership interest in such production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets. Natural gas balancing receivables are reported in "Other current assets" on the accompanying condensed consolidated balance sheets when our ownership share of production exceeds sales. As of September 30, 2017 and December 31, 2016, we did not have any material natural gas imbalances.

Accounts Receivable, Net. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both September 30, 2017 and December 31, 2016, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balance on the accompanying condensed consolidated balance sheets.

At September 30, 2017, our "Accounts receivable" balance included $16.9 million for oil and gas sales, $3.5 million due from joint interest owners, $1.1 million for severance tax credit receivables and $0.7 million for other receivables. At December 31, 2016, our "Accounts receivable" balance included $12.6 million for oil and gas sales, $2.7 million due from joint interest owners, $1.6 million for severance tax credit receivables and $0.6 million for other receivables.

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate, including our wells, in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to "General and administrative, net", on the accompanying condensed consolidated statements of operations. Our supervision fees are allocated to each well based on general and administrative costs incurred for well maintenance and support. The amount of supervision fees charged for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor) did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated were $1.1 million and $1.7 million for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively and were $3.5 million, $2.7 million and $3.0 million for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively.

Other Current Assets. Included in "Other current assets" on the accompanying condensed consolidated balance sheets are prepaid expenses totaling $1.7 million and $2.0 million at September 30, 2017 and December 31, 2016, respectively. These prepaid amounts cover well insurance, drilling contracts and various other prepaid expenses. Additionally inventories, which consist primarily of tubulars and other equipment and supplies, totaled $0.6 million and $0.4 million at September 30, 2017 and December 31, 2016, respectively.

Income Taxes. Deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

Tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likelihood of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. Our policy is to record interest and penalties relating to uncertain tax positions in income tax expense. At September 30, 2017, we did not have any accrued liability for uncertain tax positions and do not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months.

Our U.S. Federal and state income tax returns for years prior to 2015 are subject to examination to the extent of our net operating loss (NOL) carryforwards. There are no material unresolved items related to periods previously audited by these taxing authorities.

The Company has evaluated the full impact of the reorganization on our carryover tax attributes and did not incur a cash income tax liability as a result of emergence from bankruptcy on April 22, 2016. The Company fully absorbed cancellation of debt income generated in the bankruptcy reorganization with its then existing NOL carryforwards. The amount of remaining NOL carryforward available following emergence from bankruptcy was limited under United States Internal Revenue Code Sec. 382 due to the change in control. The Company's amortizable tax basis exceeded the book carrying value of its assets at April 22, 2016, at December 31, 2016 and September 30, 2017, leaving the Company in a net deferred tax asset position as of such dates. Management has determined that it is not more likely than not that the Company will realize future cash benefits from this additional tax basis and remaining carryover items and accordingly has taken a full valuation allowance to offset its tax assets.

The Company expects to incur a net taxable loss in the current taxable period thus no current income taxes are anticipated to be paid and no benefit will be recorded due to the full valuation allowance of their tax assets.

Accounts Payable and Accrued Liabilities. The "Accounts payable and accrued liabilities" balances on the accompanying condensed consolidated balance sheets are summarized below (in thousands):

	September 30, 2017	December 31, 2016
Trade accounts payable	$ 9,302	$ 10,563
Accrued operating expenses	3,167	2,990
Accrued compensation costs	4,868	4,730
Asset retirement obligations – current portion	8,558	9,965
Accrued non-income based taxes	5,123	3,937
Accrued price risk management liabilities	2,459	17,632
Accrued corporate and legal fees	2,758	3,075
Other payables	5,763	3,365
Total accounts payable and accrued liabilities	$ 41,998	$ 56,257

Cash and Cash Equivalents. We consider all highly liquid instruments with an initial maturity of three months or less to be cash equivalents. These amounts do not include cash balances that are contractually restricted.

Treasury Stock. Our treasury stock repurchases are reported at cost and are included in "Treasury stock held, at cost" on the accompanying condensed consolidated balance sheets. For the nine months ended September 30, 2017 (successor), 21,067 treasury shares were purchased to satisfy withholding tax obligations arising upon the vesting of restricted shares.

New Accounting Pronouncements. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, providing a comprehensive revenue recognition standard for contracts with customers that supersedes current revenue recognition guidance. The guidance requires entities to recognize revenue using the following five-step model: identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract, and recognize revenue as the entity satisfies each performance obligation. The Company plans to apply the modified retrospective approach upon adoption of this standard. If adoption results in an adjustment to cumulative earnings, the adjustment will be made directly to retained earnings. While our contract reviews are still in progress, we do not expect the adjustment, if any, to be material. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017.

The Company's revenues are substantially all attributable to oil and natural gas sales. Based on review of our most significant contracts, the Company believes the timing and presentation of revenues under ASU 2014-09 will be consistent with our current revenue recognition policy as described above with one probable exception. The Company currently uses the entitlement method of accounting when sales for our account are not in proportion to our ownership interest in production. To comply with ASU 2014-09, the Company expects to recognize revenue on the production sold for our account irrespective of ownership share of such production. Currently we do not have any significant imbalance situations; therefore, this is not expected to immediately impact our financial statements except for incremental disclosures. We are on track to finalize our contract reviews during the fourth quarter of 2017 and complete our implementation plans before year-end.

In February 2016, the FASB issued ASU 2016-02, which requires lessees to record most leases on the balance sheet. Under the new guidance, lease classification as either a finance lease or an operating lease will determine how lease-related revenue and expense are recognized. The guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years.

At December 31, 2016, the Company had lease commitments of approximately $8.8 million that it believes would be subject to capitalization under ASU 2016-02. This includes $1.9 million for our new corporate office sub-lease which has a term of 4.4 years and commitments for equipment and vehicle leases which total $6.5 million. The Company did not enter into any significant additional lease obligations during the first nine months of 2017. The equipment leases generally have original terms of 2 to 3 years. In some instances further analysis is needed to determine if renewal options would result in capitalized amounts in excess of the obligations during the primary lease term. Based on our preliminary assessment, we believe these leases would most likely be deemed to be operating leases under the new standard. Management plans to adopt ASU 2016-02 in the quarter ending March 31, 2019. Management continuously evaluates the economics of leasing vs. purchase for operating equipment. The lease obligations that will be in place upon adoption of ASU 2016-02 may be significantly different than the current obligations. Accordingly, at this time we cannot estimate the amount that will be capitalized when this standard is adopted.

In August 2016, the FASB issued ASU 2016-15, which provides greater clarity to preparers on the treatment of eight specific items within an entity’s statement of cash flows with the goal of reducing existing diversity on these items. The guidance is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. Early adoption is permitted, including adoption in an interim period. If an entity early adopts the ASU in an interim period, adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity that elects early adoption must adopt all of the amendments in the same period. We are currently reviewing these new requirements to determine the impact of this guidance on our financial statements.

In January 2017, the FASB issued ASU 2017-01, to assist entities in evaluating whether transactions should be accounted for as an acquisition or disposal of an asset or business. 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, the set of transferred assets and activities are not a business. The guidance is effective for companies beginning January 1, 2018 with early adoption permitted. We are currently reviewing these new requirements to determine the impact of this guidance on our financial statements.

In May 2017, the FASB issued ASU 2017-09, which provides clarity on what changes to share-based payment awards are considered substantive and require modification accounting to be applied. The guidance is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those fiscal years. The Company does not expect ASU 2017-09 to have a significant impact on our financial statements or disclosures.

(3) Share-Based Compensation

Emergence from Voluntary Reorganization

Upon the Company's emergence from bankruptcy on April 22, 2016, as discussed in Note 11 of these consolidated condensed financial statements, the Company’s issued and outstanding common stock was canceled and new common stock was issued. The Company's previous share-based compensation awards were either vested or canceled upon the Company's emergence from bankruptcy.

Share-Based Compensation Plans

Upon the Company's emergence from bankruptcy on April 22, 2016, as discussed in Note 11 of these consolidated condensed financial statements, the Company's previous share-based compensation plans were canceled and the new 2016 Equity Incentive Plan was approved in accordance with the joint plan of reorganization. Under the previous share-based compensation plan the outstanding restricted stock awards and restricted stock unit awards for most employees vested on an accelerated basis while awards issued to certain officers of the Company and the Board of Directors were canceled.

For awards granted after emergence from bankruptcy, the Company does not estimate the forfeiture rate during the initial calculation of compensation cost but rather has elected to account for forfeitures in compensation cost when they occur. For the predecessor periods, the Company had estimated the forfeiture rate for share-based compensation during the initial calculation of compensation cost.

The Company computes a deferred tax benefit for restricted stock awards, unit awards and stock options expected to generate future tax deductions by applying its effective tax rate to the expense recorded. For restricted stock units, the Company's actual tax deduction is based on the value of the units at the time of vesting.

Share-based compensation for the predecessor and successor periods are not comparable. The expense for awards issued to both employees and non-employees, which was recorded in “General and administrative, net” in the accompanying condensed consolidated statements of operations was $1.4 million and $2.9 million for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively and $4.5 million, $0.9 million and $3.1 million for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively.

Capitalized share-based compensation was $0.1 million for the three and nine months ended September 30, 2017 (successor) and $0.2 million for the period of January 1, 2016 through April 22, 2016 (predecessor). There was no capitalized share-based compensation for the three months ended September 30, 2016 (successor) and the period of April 23, 2016 through September 30, 2016 (successor).

We view stock option awards and restricted stock unit awards with graded vesting as single awards with an expected life equal to the average expected life of component awards, and we amortize the awards on a straight-line basis over the life of the awards.

Stock Option Awards

The compensation cost related to stock option awards is based on the grant date fair value and is typically expensed over the vesting period (generally one to five years). We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards with the following weighted average assumptions for stock option awards issued during the nine months ended September 30, 2017 (successor):

		Stock Option Valuation Assumptions
Expected dividend		—
Expected volatility		70.2%
Risk-free interest rate		1.98%
Expected life of stock option awards (in years)		5.7 years
Grant-date market price	$	28.62
Grant-date fair value	$	17.58

To estimate expected volatility of our 2017 stock option grants we used the historical volatility of stock prices based on a group of our peer companies.

At September 30, 2017, we had $5.4 million unrecognized compensation cost related to stock option awards. The following tables represents stock option award activity for the nine months ended September 30, 2017 (successor):

	Shares		**Wtd. Avg. Exer. Price**
Options outstanding, beginning of period (successor)	105,811	$	23.25
Options granted	370,062	$	28.62
Options forfeited	(5,844)	$	26.96
Options canceled	—	$	—
Options exercised	—	$	—
Options outstanding, end of period (successor)	470,029	$	27.43
Options exercisable, end of period (successor)	104,303	$	23.25

Our outstanding stock option awards at September 30, 2017 had $0.1 million aggregate intrinsic value. At September 30, 2017 the weighted average remaining contract life of stock option awards outstanding was 7.2 years and exercisable was 2.6 years. The total intrinsic value of stock option awards exercisable for the nine months ended September 30, 2017 (successor) was $0.1 million.

Restricted Stock Units

The 2016 equity incentive compensation plan allows for the issuance of restricted stock unit awards that generally may not be sold or otherwise transferred until certain restrictions have lapsed. The compensation cost related to these awards is based on the grant date fair value and is typically expensed over the requisite service period (generally one to five years).

As of September 30, 2017, we had unrecognized compensation expense of $8.2 million related to our restricted stock units which is expected to be recognized over a weighted-average period of 2.7 years.

The following table represents restricted stock unit award activity for the nine months ended September 30, 2017 (successor):

	Shares	Grant Date Price
Restricted stock units outstanding, beginning of period (successor)	178,847	$ 23.25
Restricted stock units granted	287,257	$ 29.07
Restricted stock units forfeited	(3,175)	$ 27.00
Restricted stock units vested	(115,453)	$ 25.44
Restricted stock units outstanding, end of period (successor)	347,476	$ 27.30

(4) Earnings Per Share

Upon the Company's emergence from bankruptcy on April 22, 2016, as discussed in Note 11 of these consolidated condensed financial statements, the Company's then outstanding common stock was canceled and new common stock and warrants were issued.

Basic earnings per share ("Basic EPS") has been computed using the weighted average number of common shares outstanding during each period. Diluted earnings per share ("Diluted EPS") assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Diluted EPS also assumes conversion of performance-based restricted stock units to common shares based on the number of shares (if any) that would be issuable, according to predetermined performance and market goals, if the end of the reporting period was the end of the performance period. As we recognized a net loss for the period of April 23, 2016 through September 30, 2016 (successor), the unvested share-based payments and stock options were not recognized in Diluted EPS calculations as they would be antidilutive. Certain of our stock options and restricted stock grants that would potentially dilute Basic EPS in the future were also antidilutive for the period of January 1, 2016 through April 22, 2016 (predecessor).

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the periods indicated below (in thousands, except per share amounts):

	Successor Three Months Ended September 30, 2017			Successor Three Months Ended September 30, 2016		
	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	$ 12,884	11,531	$ 1.12	$ 394	10,000	$ 0.04
Dilutive Securities:						
Restricted Stock Awards		—			—	
Restricted Stock Unit Awards		13			255	
Stock Option Awards		1			106	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	$ 12,884	11,545	$ 1.12	$ 394	10,361	$ 0.04

	Successor Nine Months Ended September 30, 2017			Successor from April 23, 2016 through September 30, 2016			Predecessor from January 1, 2016 through April 22, 2016		
	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount
Basic EPS:									
Net Income (Loss) and Share Amounts	$ 46,834	11,417	$ 4.10	$ (149,207)	10,000	$ (14.92)	$ 851,611	44,692	$ 19.06
Dilutive Securities:									
Restricted Stock Awards		—			—			1,005	
Restricted Stock Unit Awards		53			—			—	
Stock Option Awards		9			—			—	
Diluted EPS:									
Net Income (Loss) and Assumed Share Conversions	$ 46,834	11,479	$ 4.08	$ (149,207)	10,000	$ (14.92)	$ 851,611	45,697	$ 18.64

All stock options to purchase shares and restricted stock unit awards were dilutive for the three months ended September 30, 2016 (successor) and were included in the table above.

Approximately 1.3 million stock options to purchase shares were not included in the computation of Diluted EPS for the period of January 1, 2016 through April 22, 2016 (predecessor), because their exercise price was out of the money, while 0.4 million and 0.3 million stock options to purchase shares were not included in the computation of Diluted EPS for the three and nine months ended September 30, 2017 (successor), respectively, because these stock options were antidilutive.

Approximately 0.3 million restricted stock awards for each of the period of January 1, 2016 through April 22, 2016 (predecessor) were not included in the computation of Diluted EPS because they were antidilutive.

Approximately 0.8 million shares related to performance-based restricted stock units that could be converted to common shares were not included in the computation of Diluted EPS because the performance and market conditions had not been met for the period of January 1, 2016 through April 22, 2016 (predecessor). Approximately 0.2 million and 0.1 million shares of restricted stock units that could be converted to common shares were not included in the computation of Diluted EPS for the three and nine months ended September 30, 2017, respectively, because they were antidilutive.

Approximately 4.3 million warrants to purchase common stock were not included in the computation of Diluted EPS for the nine months ended September 30, 2017 (successor) because these warrants were antidilutive.

(5) Long-Term Debt

Revolving Credit Facility. Amounts outstanding under our Credit Facility (defined below) were $250.0 million and $198.0 million as of September 30, 2017 and December 31, 2016, respectively. As discussed in Note 11 of these condensed consolidated financial statements, on April 22, 2016 (the "Effective Date"), the Prior First Lien Credit Facility was terminated and paid in full, and the Company entered into a Senior Secured Revolving Credit Agreement among the Company, as borrower, JPMorgan Chase Bank, National Association, as administrative agent, and certain lenders party thereto. On April 19, 2017, the Company amended and restated the Senior Secured Revolving Credit Agreement by entering into a First Amended and Restated Senior Secured Revolving Credit Agreement (the "Credit Agreement") among the Company, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain lenders that are a party thereto, which provides for revolving loans of up to the borrowing base then in effect (the "Credit Facility"). The Credit Facility matures April 19, 2022. The maximum credit amount under the Credit Facility is currently $600 million with an initial borrowing base of $330 million. The borrowing base is scheduled to be redetermined in May and November of each calendar year, commencing November 2017, and is subject to additional adjustments from time to time, including for asset sales, elimination or reduction of hedge positions and incurrence of other debt. Additionally, each of the Company and the administrative agent may request an unscheduled redetermination of the borrowing base between scheduled redeterminations. The amount of the borrowing base is determined by the lenders in their discretion and consistent with their oil and gas lending criteria at the time of the relevant redetermination. The Company may also request the issuance of letters of credit under the Credit Agreement in an aggregate amount up to $25 million, which reduce the amount of available borrowings under the borrowing base in the amount of such issued and outstanding letters of credit.

Interest under the Credit Facility accrues at the Company's option either at an Alternative Base Rate plus the applicable margin ("ABR Loans") or the LIBOR Rate plus the applicable margin ("Eurodollar Loans"). The applicable margin ranges from 1.75% to 2.75% for ABR Loans and 2.75% to 3.75% for Eurodollar Loans. The Alternate Base Rate and LIBOR Rates are defined, and the applicable margins are set forth, in the Credit Agreement. Undrawn amounts under the Credit Facility are subject to a 0.50% commitment fee. To the extent that a payment default exists and is continuing, all amounts outstanding under the Credit Facility will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto.

The obligations under the Credit Agreement are secured, subject to certain exceptions, by a first priority lien on substantially all assets of the Company and certain of its subsidiaries, including a first priority lien on properties attributed with at least 85% of estimated proved reserves of the Company and its subsidiaries.

The Credit Agreement contains the following financial covenants:

- a ratio of total debt to EBITDA, as defined in the Credit Agreement, for the most recently completed four fiscal quarters, not to exceed 4.0 to 1.0 as of the last day of each fiscal quarter; and

- a current ratio, as defined in the Credit Agreement and which includes in the numerator available borrowings undrawn under the borrowing base, of not less than 1.0 to 1.0 as of the last day of each fiscal quarter.

As of September 30, 2017, the Company was in compliance with all financial covenants under the Credit Agreement.

Additionally, the Credit Agreement contains certain representations, warranties and covenants, including but not limited to, limitations on incurring debt and liens, limitations on making certain restricted payments, limitations on investments, limitations on asset sales and hedge unwinds, limitations on transactions with affiliates and limitation on modifying organizational documents and material contracts. The Credit Agreement contains customary events of default. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Credit Facility to be immediately due and payable.

Interest expense on the Credit Facility, which includes commitment fees and amortization of debt issuance costs, totaled $3.0 million and $11.6 million for the three and nine months ended September 30, 2017 (successor), and $6.1 million and $10.4 million for the three months ended September 30, 2016 (successor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. Additionally, interest expense for the nine months ended September 30, 2017 includes a write-down of debt issuance costs of $2.4 million. The amount of commitment fee amortization included in interest expense, net was $0.1 million and $0.4 million for the three and nine months ended September 30, 2017 (successor) and less than $0.1 million and $0.1 million for the three months ended September 30, 2016 (successor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively.

We capitalized interest on our unproved properties in the amount $0.2 million and $0.5 million for the three and nine months ended September 30, 2017 (successor) and $0.3 million for both the three months ended September 30, 2016 (successor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively.

Debt Issuance Costs. Our policy is to capitalize upfront commitment fees and other direct expenses associated with our line of credit arrangement and then amortize such costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings.

Bankruptcy Filing. As discussed in Note 11 of these consolidated condensed financial statements, the Chapter 11 filing of the Company and the Chapter 11 Subsidiaries constituted an event of default with respect to our then-existing debt obligations. As a result, the Company's pre-petition unsecured senior notes and secured debt under the Company's previous credit facility (the "Prior First Lien Credit Facility") became immediately due and payable, but any efforts to enforce such payment obligations were automatically stayed as a result of the Chapter 11 filing. On April 22, 2016, upon the Company's emergence from bankruptcy, the senior notes and borrowing under the debtor-in-possession credit facility ("DIP Credit Agreement") (along with certain unsecured claims as discussed further in Note 11) were exchanged for 88.5% of the common stock of the reorganized entity. Additional information regarding the bankruptcy proceedings is included in Note 11 of these condensed consolidated financial statements.

Debtor-In-Possession Financing. As part of the Chapter 11 filings, we entered into a debtor-in-possession credit facility ("DIP Credit Agreement"). The proceeds of borrowings under the DIP Credit Agreement were primarily used to pay down the pre-petition Prior First Lien Credit Facility upon emergence from bankruptcy, and were also used to pay certain costs, fees and expenses related to the Chapter 11 cases, authorized pre-petition claims, and amounts due in connection with the DIP Credit Agreement, including on account of certain "adequate protection" obligations. Pursuant to the Plan, the DIP Credit Agreement, at the option of the lenders, converted into the post-emergence Company's common stock, which was part of the 88.5% of the common stock distributed to the then current holders of the senior notes and certain unsecured creditors upon emergence from the bankruptcy proceedings. As a result, the $75.0 million borrowed under the DIP Credit Agreement was not required to be repaid and terminated upon the Company's exit from bankruptcy.

We paid the lenders under the DIP Credit Agreement a 3.0% commitment fee, at the time funds were made available under the facility. The commitment fee was included in interest expense during the period of January 1, 2016 through April 22, 2016 (predecessor). Total interest expense on the DIP Credit Agreement was $6.4 million for the period of January 1, 2016 through April 22, 2016 (predecessor).

Prior First Lien Credit Facility Bank Borrowings. During the bankruptcy proceedings we paid interest on our Prior First Lien Credit Facility in the normal course. Interest expense on the Prior First Lien Credit Facility, including commitment fees and amortization of debt issuance costs, totaled $6.8 million for the period of January 1, 2016 through April 22, 2016 (predecessor). The amount of commitment fees included in interest expense, net was immaterial for the period of January 1, 2016 through April 22, 2016 (predecessor), respectively. We did not capitalize interest on our unproved properties for the period of January 1, 2016 through April 22, 2016 (predecessor).

Prior Senior Notes Due. On April 22, 2016, the obligations of the Company and the Chapter 11 Subsidiaries with respect to these notes were canceled pursuant to the plan of reorganization and the holders thereof were issued common stock of the post-emergence entity in exchange therefor. There was no interest expense on the senior notes, for the period of January 1, 2016 through April 22, 2016 (predecessor) due to our bankruptcy proceedings. Contractual interest on the senior notes for the period of January 1, 2016 through April 22, 2016 (predecessor) totaled $21.6 million.

(6) Acquisitions and Dispositions

On April 15, 2016, we sold to Texegy LLC a 75% working interest share of the Company's holdings in the South Bearhead Creek and Burr Ferry field areas located in Central Louisiana. The net proceeds of $46.9 million received by the Company in this transaction, including deposits received prior to the closing date, were credited to the full cost pool and used primarily to reduce the amount of borrowings under the Company's Prior First Lien Credit Facility, and for other general corporate purposes. This disposition also included the buyer's assumption of approximately $6.5 million of plugging and abandonment liability. No gain or loss was recorded on the sale of this property.

Effective April 25, 2016, we disposed of our Masters Creek field in Central Louisiana. We received net proceeds of less than $0.1 million and the buyer's assumption of approximately $8.1 million of plugging and abandonment liability. No gain or loss was recorded on the sale of this property.

Effective September 30, 2016, we closed our transaction with Blue Marble Resources LLC for the sale of the Company's holdings in our Sun TSH field located in South Texas. We received net proceeds of approximately $0.9 million and the buyer assumed approximately $1.8 million of plugging and abandonment liability. No gain or loss was recorded on the sale of the property.

Effective July 31, 2017, we disposed of a portion of our AWP Olmos wells in South Texas. We received net proceeds of $0.7 million and the buyer's assumption of approximately $0.5 million of plugging and abandonment liability. No gain or loss was recorded on the sale of this property.

There were no acquisitions of developed properties during the three and nine months ended September 30, 2017.

(7) Price-Risk Management Activities

Derivatives are recorded on the balance sheet at fair value with changes in fair value recognized in earnings. The changes in the fair value of our derivatives are recognized in "Net gain (loss) on commodity derivatives" on the accompanying condensed consolidated statements of operations. We have a price-risk management policy to use derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of commodity price swaps and collars as well as basis swaps.

During the three months ended September 30, 2017 (successor) and the nine months ended September 30, 2017 (successor) the Company recorded losses of $1.6 million and gains of $14.5 million, respectively, on its commodity derivatives. During the three months ended September 30, 2016 (successor) and the period of April 23, 2016 through September 30, 2016 (successor) the Company recorded gains of $2.6 million and losses of $7.3 million, respectively, on its commodity derivatives. The Company received net cash payments of $0.1 million and made net cash payments of $2.5 million for settled derivative contracts during the three and nine months ended September 30, 2017 (successor), respectively, and net cash payments of $1.1 million during the period of April 23, 2016 through September 30, 2016 (successor). During the period of January 1, 2016 through April 22, 2016 (predecessor), there were no gains or losses as there were no outstanding hedge agreements.

At September 30, 2017 and December 31, 2016, we had $0.5 million and $0.4 million, respectively, in receivables for settled derivatives which were recognized on the accompanying condensed consolidated balance sheet in “Accounts receivable, net” and were subsequently collected in October 2017 and January 2017, respectively. At September 30, 2017 and December 31, 2016, we also had $0.2 million and $1.8 million, respectively, in payables for settled derivatives which were recognized on the accompanying condensed consolidated balance sheet in "Accounts payable and accrued liabilities" and were subsequently paid in October 2017 and January 2017, respectively.

The fair values of our derivatives are computed using commonly accepted industry-standard models and are periodically verified against quotes from brokers. At September 30, 2017, there was $2.8 million and $0.8 million in current and long-term unsettled derivative assets and $2.5 million and $2.2 million in current and long-term unsettled derivative liabilities, respectively. At December 31, 2016, there was $0.5 million in current unsettled derivative assets and $15.8 million and $1.0 million in current and long-term unsettled derivative liabilities, respectively, while our long-term unsettled derivative assets were not material.

The Company uses an International Swap and Derivatives Association master agreement for our derivative contracts. This is an industry standardized contract containing the general conditions of our derivative transactions including provisions relating to netting derivative settlement payments under certain circumstances (such as default). For reporting purposes, the Company has elected to not offset the asset and liability fair value amounts of its derivatives on the accompanying balance sheets. Under the right of set-off, there was a $1.1 million net fair value liability at September 30, 2017 and a $16.4 million net fair value liability at December 31, 2016, respectively. For further discussion related to the fair value of the Company's derivatives, refer to Note 8 of these condensed consolidated financial statements.

The following tables summarize the weighted average prices as well as future production volumes for our unsettled derivative contracts in place as of September 30, 2017:

Oil Derivative Swaps (NYMEX WTI Settlements)	Total Volumes (Bbls)	Weighted Average Price
2017 Contracts		
4Q17	107,298	$ 48.56
2018 Contracts		
1Q18	98,000	$ 50.77
2Q18	94,400	$ 50.68
3Q18	90,400	$ 50.65
4Q18	86,800	$ 50.56
2019 Contracts		
1Q19	11,400	$ 50.72
2Q19	11,400	$ 50.72
3Q19	9,000	$ 50.50
4Q19	9,000	$ 50.50

Natural Gas Derivative Contracts (NYMEX Henry Hub Settlements)	Total Volumes (MMBtu)	Weighted Average Swap Price	Weighted Average Collar Floor Price	Weighted Average Collar Call Price
2017 Swap Contracts				
4Q17	4,203,334	$ 3.11		
2017 Collar Contracts				
4Q17	2,068,000		$ 3.10	$ 3.72
2018 Swap Contracts				
1Q18	7,445,000	$ 3.46		
2Q18	8,155,000	$ 2.86		
3Q18	7,874,000	$ 2.88		
4Q18	7,976,000	$ 2.96		
2019 Swap Contracts				
1Q19	4,181,000	$ 3.12		
2Q19	4,200,000	$ 2.82		
3Q19	4,200,000	$ 2.82		
4Q19	4,200,000	$ 2.82		
2020 Swap Contracts				
1Q20	4,200,000	$ 2.82		

Natural Gas Basis Derivative Swap (East Texas Houston Ship Channel vs NYMEX Settlements)	Total Volumes (MMBtu)	Weighted Average Price	
2017 Contracts			
4Q17	4,893,334	$	(0.04)
2018 Contracts			
1Q18	5,400,000	$	(0.12)
2Q18	3,610,000	$	(0.04)
3Q18	3,020,000	$	(0.03)
4Q18	2,270,000	$	(0.09)
2019 Contracts			
1Q19	750,000	$	(0.11)

(8) Fair Value Measurements

Fair Value on a Recurring Basis. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable and accrued liabilities approximate fair value due to the highly liquid or short-term nature of these instruments.

The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

Level 1 – Uses quoted prices in active markets for identical, unrestricted assets or liabilities. Instruments in this category have comparable fair values for identical instruments in active markets.

Level 2 – Uses quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets. Instruments in this category are periodically verified against quotes from brokers and include our commodity derivatives that we value using commonly accepted industry-standard models which contain inputs such as contract prices, risk-free rates, volatility measurements and other observable market data that are obtained from independent third-party sources.

Level 3 – Uses unobservable inputs for assets or liabilities that are in non-active markets.

The following table presents our assets and liabilities that are measured on a recurring basis at fair value as of September 30, 2017 and December 31, 2016 and are categorized using the fair value hierarchy. For additional discussion related to the fair value of the Company's derivatives, refer to Note 7 of these condensed consolidated financial statements.

	Fair Value Measurements at			
(in millions)	Total	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
September 30, 2017				
Assets				
Natural Gas Derivatives	$ 3.0	$ —	$ 3.0	$ —
Natural Gas Basis Derivatives	$ 0.5	$ —	$ 0.5	$ —
Oil Derivatives	$ 0.1	$ —	$ 0.1	$ —
Liabilities				
Natural Gas Derivatives	$ 3.6	$ —	$ 3.6	$ —
Natural Gas Basis Derivatives	$ 0.2	$ —	$ 0.2	$ —
Oil Derivatives	$ 0.9	$ —	$ 0.9	$ —
December 31, 2016				
Assets				
Natural Gas Basis Derivatives	$ 0.4	$ —	$ 0.4	$ —
Liabilities				
Natural Gas Derivatives	$ 13.7	$ —	$ 13.7	$ —
Natural Gas Basis Derivatives	$ 0.1	$ —	$ 0.1	$ —
Oil Derivatives	$ 3.0	$ —	$ 3.0	$ —

Our current and long-term unsettled derivative assets and liabilities in the table above are measured at gross fair value and are shown on the accompanying condensed consolidated balance sheets in “Other current assets”, "Other long-term assets", "Accounts payable and accrued liabilities" and "Other long-term liabilities", respectively.

(9) Asset Retirement Obligations

Liabilities for legal obligations associated with the retirement obligations of tangible long-lived assets are initially recorded at fair value in the period in which they are incurred. When a liability is initially recorded, the carrying amount of the related asset is increased. The liability is discounted from the expected date of abandonment. Over time, accretion of the liability is recognized each period, and the capitalized cost is amortized on a unit-of-production basis as part of depreciation, depletion, and amortization expense for our oil and gas properties. Upon settlement of the liability, the Company either settles the obligation for its recorded amount or incurs a gain or loss upon settlement which is included in the “Property and Equipment” balance on our accompanying condensed consolidated balance sheets. This guidance requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values.

Upon the Company's emergence from bankruptcy on April 22, 2016, as discussed in Note 12 of these condensed consolidated financial statements, the Company applied fresh start accounting. This included adjusting the Asset Retirement Obligations based on the estimated fair values at April 22, 2016. The following provides a roll-forward of our asset retirement obligations for the nine months ended September 30, 2017 (in thousands):

	2017
Asset Retirement Obligations recorded as of January 1	$ 32,256
Accretion	1,722
Liabilities incurred for new wells and facilities construction	242
Reductions due to sold wells and facilities	(601)
Reductions due to plugged wells and facilities	(2,278)
Revisions in estimates	1,391
Asset Retirement Obligations as of September 30	$ 32,732

At September 30, 2017 and December 31, 2016, approximately $8.6 million and $10.0 million of our asset retirement obligations were classified as a current liability in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.

(10) Commitments and Contingencies

In the ordinary course of business, we are party to various legal actions, which arise primarily from our activities as operator of oil and natural gas wells. In management's opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

(11) Emergence from Voluntary Reorganization under Chapter 11 Proceedings

On December 31, 2015, Swift Energy Company and eight of its U.S. subsidiaries (the "Chapter 11 Subsidiaries") filed voluntary petitions seeking relief under Chapter 11 of Title 11 of the U.S. Bankruptcy Code (the "Bankruptcy Code") in the U.S. Bankruptcy Court for the District of Delaware under the caption *In re Swift Energy Company, et al* (Case No. 15-12670). The Company and the Chapter 11 Subsidiaries received bankruptcy court confirmation of their joint plan of reorganization on March 31, 2016, and subsequently emerged from bankruptcy on April 22, 2016 (the "Effective Date").

Effect of the Bankruptcy Proceedings. During the bankruptcy proceedings, the Company conducted normal business activities and was authorized to pay and has paid (subject to caps applicable to payments of certain pre-petition obligations) pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders and critical vendors, pre-petition amounts owed to pipeline owners that transport the Company's production, and funds belonging to third parties, including royalty holders and partners.

In addition, subject to certain specific exceptions under the Bankruptcy Code, the Chapter 11 filings automatically stayed most judicial or administrative actions against the Company and efforts by creditors to collect on or otherwise exercise rights or remedies with respect to pre-petition claims. As a result, we did not record interest expense on the Company’s senior notes for the period of January 1, 2016 through April 22, 2016 (predecessor). For that period, contractual interest on the senior notes totaled $21.6 million.

Plan of Reorganization. Pursuant to the Plan, the significant transactions that occurred upon emergence from bankruptcy were as follows:

- the approximately $906 million of indebtedness outstanding on account of the Company’s senior notes, $75.0 million in borrowings under the Company's DIP Credit Agreement and certain other unsecured claims were exchanged for 88.5% of the post-emergence Company’s common stock;
- the lenders under the DIP Credit Agreement received an additional backstop fee consisting of 7.5% of the post-emergence Company’s common stock;
- the Company’s pre-petition common stock was canceled and the current shareholders received 4% of the post-emergence Company’s common stock and warrants to purchase up to 30% of the reorganized Company's equity. See Note 12 of these condensed consolidated financial statements for more information;
- claims of other creditors were paid in full in cash, reinstated or otherwise treated in a manner acceptable to the creditors;

- the Company entered into a registration rights agreement to provide customary registration rights to certain holders of the Company's post-emergence common stock who, together with their affiliates received upon emergence 5% or more of the outstanding common stock of the Company;
- the Company sold (effective April 15, 2016) a portion of its interest in its Central Louisiana fields known as Burr Ferry and South Bearhead Creek to Texegy LLC, for net proceeds of approximately $46.9 million including deposits received prior to the closing date; and
- the Prior First Lien Credit Facility was terminated and a new senior secured credit facility (the "Credit Facility") with an initial $320 million borrowing base was established. For more information refer to Note 5 of these condensed consolidated financial statements.

In accordance with the Plan, the post-emergence Company's new board of directors was initially to be made up of seven directors consisting of the Chief Executive Officer, two directors appointed by Strategic Value Partners LLC ("SVP"), a former holder of the Company's senior notes, two directors appointed by other former holders of the Company's senior notes, one additional independent director and one independent new non-executive chairman of the Board. In addition, pursuant to the Plan, SVP and the other former holders of the Company's senior notes were given certain continuing director nomination rights subject to minimum share ownership conditions.

DIP Credit Agreement. In connection with the pre-petition negotiations of the restructuring support agreement, certain holders of the Company's senior notes agreed to provide the Company and the Chapter 11 Subsidiaries a debtor-in-possession credit facility. The DIP Credit Agreement provided for a multi-draw term loan of up to $75.0 million, which became available to the Company upon the satisfaction of certain milestones and contingencies. Upon emergence from bankruptcy, the Company had drawn down the entire $75.0 million available. Pursuant to the Plan, the borrowings under the DIP Credit Agreement, at the option of the lenders to the DIP Credit Agreement, converted into the post-emergence Company's common stock, which was part of the 88.5% of the common stock distributed to the holders of the Company's senior notes and certain unsecured creditors. As such, the $75.0 million borrowed under the DIP Credit Agreement was not required to be repaid in cash and was terminated upon the Company's exit from bankruptcy. For more information refer to Note 5 of these condensed consolidated financial statements.

(12) Fresh Start Accounting

Upon the Company's emergence from Chapter 11 bankruptcy, the Company adopted fresh start accounting, pursuant to FASB Accounting Standards Codification ("ASC") 852, "*Reorganizations*", and applied the provisions thereof to its financial statements. The Company qualified for fresh start accounting because (i) the holders of existing voting shares of the pre-emergence debtor-in-possession, referred to herein to as the "Predecessor" or "Predecessor Company," received less than 50% of the voting shares of the post-emergence successor entity, which we refer to herein as the "Successor" or "Successor Company" and (ii) the reorganization value of the Company's assets immediately prior to confirmation was less than the post-petition liabilities and allowed claims. The Company applied fresh start accounting as of April 22, 2016, when it emerged from bankruptcy protection. Adopting fresh start accounting results in a new reporting entity for financial reporting purposes with no beginning retained earnings or deficit. The cancellation of all existing shares outstanding on the Effective Date and issuance of new shares of the Successor Company caused a related change of control of the Company under ASC 852. Upon the application of fresh start accounting, the Company allocated the reorganization value to its individual assets based on their estimated fair values. Reorganization value represents the fair value of the Successor Company's assets before considering liabilities.

Reorganization Value. Reorganization value represents the fair value of the Successor Company's total assets and is intended to approximate the amount a willing buyer would pay for the assets immediately after restructuring. Under fresh start accounting, we allocated the reorganization value to our individual assets based on their estimated fair values.

Our reorganization value was derived from an estimate of enterprise value. Enterprise value represents the estimated fair value of an entity's long-term debt and shareholders' equity. In support of the Plan, the enterprise value of the Successor Company was estimated and approved by the bankruptcy court to be in the range of $460 million to $800 million. Based on the estimates and assumptions used in determining the enterprise value, as further discussed below, the Company estimated the enterprise value to be approximately $474 million. This valuation analysis was prepared using reserve information, development schedules, other financial information and financial projections and applying standard valuation techniques, including risked net asset value analysis and public comparable company analyses.

Valuation of Oil and Gas Properties. The Company determined the fair value of its oil and gas properties based on the discounted cash flows expected to be generated from these assets. The computations were based on market conditions and reserves in place as of the bankruptcy emergence date.

The Company's Reserves Engineers developed full cycle production models for all of the Company's developed wells and identified undeveloped drilling locations within the Company's leased acreage. The undeveloped locations were categorized based on varying levels of risk using industry standards. The proved locations were limited to wells expected to be drilled in the Company's five-year plan. The locations were then segregated into geographic areas. Future cash flows before application of risk factors were estimated by using the New York Mercantile Exchange five-year forward prices for West Texas Intermediate oil and Henry Hub natural gas with inflation adjustments applied to periods beyond five years. These prices were adjusted for typical differentials realized by the Company for location and product quality adjustments. Transportation cost estimates were based on agreements in place at the emergence date. Development and operating costs were based on the Company's recent cost trends adjusted for inflation.

Risk factors were determined separately for each geographic area. Based on the geological characteristics of each area appropriate risk factors for each of the reserve categories were applied. The Company considered production, geological and mechanical risk to determine the probability factor for each reserve category in each area.

The risk adjusted after tax cash flows were discounted at 12%. This discount factor was derived from a weighted average cost of capital computation which utilized a blended expected cost of debt and expected returns on equity for similar industry participants. The after tax cash flow computations included utilization of the Company's unamortized tax basis in the properties as of the emergence date. Plugging and abandonment costs were included in the cash flow projections for undeveloped reserves but were excluded for developed reserves since the fair value of this liability was determined separately and included in the emergence date liabilities reported on the balance sheet.

From this analysis the Company concluded the fair value of its proved reserves was $509.4 million, and the value of its probable reserves was $45.5 million as of the effective date. The fair value of the possible reserves was determined to be de minimus and no value was therefore recognized. The value of probable reserves was classified as unevaluated costs. The Company also reviewed its undeveloped leasehold acreage and concluded that the fair value of its probable reserves appropriately captured the fair value of its undeveloped leasehold acreage. These amounts are reflected in the Fresh Start Adjustments item number 12 below.

The following table reconciles the enterprise value to the estimated fair value of the Successor Company's common stock as of the Effective Date (in thousands):

		April 22, 2016
Enterprise Value	$	473,660
Plus: Cash and cash equivalents		8,739
Less: Fair value of debt		(253,000)
Less: Fair value of warrants		(14,967)
Fair value of Successor common stock	$	214,432
Shares outstanding at April 22, 2016		10,000
Per share value	$	21.44

Upon issuance of the Credit Facility on April 22, 2016, the Company received net proceeds of approximately $253 million and incurred debt issuance costs of approximately $7.0 million.

In accordance with the Plan, the Company issued two series of warrants (each for up to 15% of the reorganized Company's equity) to the former holders of the Company's common stock, one to expire on the close of business on April 22, 2019 (the "2019 Warrants") and the other to expire on the close of business on April 22, 2020 (the "2020 Warrants" and, together with the 2019 Warrants, the "Warrants"). Following the Effective Date, there were 2019 Warrants outstanding to purchase up to an aggregate of 2,142,857 shares of Common Stock at an initial exercise price of $80.00 per share. Following the Effective Date, there were 2020 Warrants outstanding to purchase up to an aggregate of 2,142,857 shares of Common Stock at an initial exercise price of $86.18 per share. All unexercised Warrants shall expire, and the rights of the holders of such Warrants (the "Warrant Holders") to purchase Common Stock shall terminate at the close of business on the first to occur of (i) their respective expiration dates or (ii) the date of completion of (A) any Fundamental Equity Change (as defined in the Warrant Agreement) or (B) an Asset Sale (as defined in the Warrant Agreement). The fair value of the 2019 and 2020 Warrants was $3.26 and $3.73 per warrant, respectively. A Black-Scholes pricing model with the following assumptions was used in determining the fair value: strike price of $80 and $86.18; expected volatility of 70% and 65%; expected dividend rate of 0.0%; risk free interest rate of 1.01% and 1.19%; and expiration date of 3 and 4 years, respectively. The fair value of these warrants was estimated using Level 2 inputs (for additional discussion of the Level 2 inputs, refer to Note 8 of these condensed consolidated financial statements).

The following table reconciles the enterprise value to the estimated reorganization value as of the Effective Date (in thousands):

		April 22, 2016
Enterprise Value	$	473,660
Plus: Cash and cash equivalents		8,739
Plus: Other working capital liabilities		73,318
Plus: Other long-term liabilities		58,992
Reorganization value of Successor assets	$	614,709

Reorganization value and enterprise value were estimated using numerous projections and assumptions that are inherently subject to significant uncertainties and resolution of contingencies that are beyond our control. Accordingly, the estimates set forth herein are not necessarily indicative of actual outcomes, and there can be no assurance that the estimates, projections or assumptions will be realized.

Condensed Consolidated Balance Sheet. The adjustments set forth in the following condensed consolidated balance sheet reflect the effect of the consummation of the transactions contemplated by the Plan (reflected in the column "Reorganization Adjustments") as well as fair value adjustments as a result of the adoption of fresh start accounting (reflected in the column "Fresh Start Adjustments"). The explanatory notes highlight methods used to determine fair values or other amounts of the assets and liabilities as well as significant assumptions.

The following table reflects the reorganization and application of ASC 852 on our condensed consolidated balance sheet as of April 22, 2016 (in thousands):

	Predecessor Company	Reorganization Adjustments	Fresh Start Adjustments	Successor Company
ASSETS				
Current Assets:				
Cash and cash equivalents	$ 57,599	$ (48,860) (1)	$ —	$ 8,739
Accounts receivable	34,278	(597) (2)	—	33,681
Other current assets	3,503	—	—	3,503
Total current assets	95,380	(49,457)	—	45,923
Property and equipment	6,007,326	—	(5,448,759) (12)	558,567
Less - accumulated depreciation, depletion and amortization	(5,676,252)	—	5,676,252 (12)	—
Property and equipment, net	331,074	—	227,493	558,567
Other long-term assets	4,629	6,388 (3)	(798) (13)	10,219
Total Assets	$ 431,083	$ (43,069)	$ 226,695	$ 614,709

	Predecessor Company	Reorganization Adjustments	Fresh Start Adjustments	Successor Company
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current Liabilities:				
Accounts payable and accrued liabilities	$ 64,324	$ (4,666) (4)	$ (885) (14)	$ 58,773
Accrued capital costs	5,410	—	—	5,410
Accrued interest	768	(104) (5)	—	664
Undistributed oil and gas revenues	8,471	—	—	8,471
Current portion of debt	364,500	(364,500) (6)	—	—
Total current liabilities	443,473	(369,270)	(885)	73,318
Long-term debt	—	253,000 (7)	—	253,000
Asset retirement obligation	51,800	—	6,101 (14)	57,901
Other long-term liabilities	2,124	—	(1,033) (15)	1,091
Liabilities subject to compromise	911,381	(911,381) (8)	—	—
Total Liabilities	1,408,778	(1,027,651)	4,183	385,310
Stockholders' Equity:				
Preferred stock		—	—	—
Common stock (Predecessor)	450	(450) (9)	—	—
Common stock (Successor)	—	100 (10)	—	100
Additional paid-in capital (Predecessor)	777,475	(777,475) (9)	—	—
Additional paid-in capital (Successor)	—	229,299 (10)	—	229,299
Treasury stock held at cost	(2,496)	2,496 (9)	—	—
Retained earnings (accumulated deficit)	(1,753,124)	1,530,612 (11)	222,512 (16)	—
Total Stockholders' Equity (Deficit)	(977,695)	984,582	222,512	229,399
Total Liabilities and Stockholders' Equity	$ 431,083	$ (43,069)	$ 226,695	$ 614,709

Notes to Above Reorganization Adjustments

1. Reflects the net cash payments recorded as of the Effective Date from implementation of the Plan (in thousands):

Sources:		
Net proceeds from Credit Facility	$	253,000
Total Sources	$	253,000
Uses:		
Repayment of Prior First Lien Credit Facility	$	289,500
Debt issuance costs		6,482
Predecessor accounts payable paid upon emergence		5,878
Total Uses	$	301,860
Net Uses	$	(48,860)

2. Reflects the impairment of a short-term leasehold improvement build-out receivable for $0.6 million that will no longer be reimbursed by the building lessor as the Company's office lease contract was rejected as part of the bankruptcy.

3. Reflects the capitalization of debt issuance costs on the Credit Facility for $7.0 million, of which $6.5 million was paid on emergence and $0.5 million included in accounts payable and accrued liabilities and paid in the subsequent month, as well as the impairment of a long-term leasehold improvement build-out receivable for $0.6 million relating to an office lease contract that was rejected in connection with the bankruptcy.

4. Reflects the settlement of predecessor accounts payable of $5.2 million partially offset by capitalized debt issuance costs of $0.5 million.

5. Reflects the settlement of accrued interest on the Company's DIP Credit Agreement which was equitized upon emergence.

6. On the Effective Date, the Company repaid in full all borrowings outstanding of $289.5 million under the Prior First Lien Credit Facility. In addition the Company equitized the outstanding DIP Credit Agreement borrowings of $75 million via the issuance of equity valued at $142.3 million.

7. Reflects the $253 million in new borrowings under the Credit Facility.

8. Liabilities subject to compromise were settled as follows in accordance with the Plan (in thousands):

7.125% senior notes due 2017	$	250,000
8.875% senior notes due 2020		225,000
7.875% senior notes due 2022		400,000
Accrued interest		30,043
Accounts payable and accrued liabilities		1,713
Other long-term liabilities		4,625
Liabilities subject to compromise of the Predecessor Company (LSTC)		911,381
Fair value of equity issued to former holders of the senior notes of the Predecessor		(47,443)
Gain on settlement of Liabilities subject to compromise	$	863,938

9. Reflects the cancellation of the Predecessor Company equity to retained earnings.

10. Reflects the issuance of 10.0 million shares of common stock at a per share price of $21.44 and 4.3 million warrants to purchase up to 30% of the reorganized Company's equity valued at $15.0 million with an average per unit value of $3.49. Former holders of the senior notes and certain unsecured creditors were issued 8.85 million shares of common stock while the Backstop

Lenders (as defined in the DIP Credit Agreement) were issued 0.75 million shares of common stock. Former shareholders received the warrants and 0.4 million shares of common stock.

11. Reflects the cumulative impact of the reorganization adjustments discussed above as of the Effective Date (in thousands):

Gain on settlement of Liabilities subject to compromise	$ 863,938
Fair value of equity issued in excess of DIP principal	(67,329)
Fair value of equity and warrants issued to Predecessor stockholders	(23,544)
Fair value of equity issued to DIP lenders for backstop fee	(16,082)
Other reorganization adjustments	(1,800)
Cancellation of Predecessor Company equity	775,429
Net impact to accumulated deficit	$ 1,530,612

Fresh Start Adjustments

12. The following table summarizes the fair value adjustment on our oil and gas properties and accumulated depletion, depreciation and amortization as of the Effective Date (in thousands):

	Predecessor Company	Fresh Start Adjustments	Successor Company
Oil and Gas Properties			
Proved properties	$ 5,951,016	$ (5,441,655)	$ 509,361
Unproved properties	12,057	33,448	45,505
Total Oil and Gas Properties	5,963,073	(5,408,207)	554,866
Less - Accumulated depletion and impairments	(5,638,741)	5,638,741	—
Net Oil and Gas Properties	324,332	230,534	554,866
Furniture, Fixtures, and other equipment	44,252	(40,551)	3,701
Less - Accumulated depreciation	(37,510)	37,510	—
Net Furniture, Fixtures and other equipment	$ 6,742	$ (3,041)	$ 3,701
Net Oil and Gas Properties, Furniture and fixtures and accumulated depreciation	$ 331,074	$ 227,493	$ 558,567

13. Reflects the adjustment of other non-current assets to fair value.

14. Reflects the current and long-term portion of the Company's asset retirement obligation computed in accordance with ASC 410-20, applying the appropriate discount rate to future costs as of the emergence date, which the Company has determined to be a reasonable fair value estimate.

15. Reflects the adjustment of other non-current liabilities to fair value.

16. Reflects the cumulative impact of fresh start adjustments as discussed above.

Reorganization Items

Reorganization items represent liabilities settled, net of amounts incurred subsequent to the Chapter 11 filing as a direct result of the Plan and are classified as "(Gain) Loss on Reorganization items, net" in the Condensed Consolidated Statements of Operations. The following table summarizes reorganization items (in thousands):

	Successor	Predecessor
	Period from April 23, 2016 through September 30, 2016	Period from January 1, 2016 through April 22, 2016
Gain on settlement of liabilities subject to compromise	$ —	$ (863,938)
Fair value of equity issued in excess of DIP principal	—	67,329
Fresh start adjustments	—	(222,512)
Reorganization legal and professional fees and expenses	1,595	25,573
Fair value of equity issued to DIP lenders for backstop fee	—	16,082
Other reorganization items	(126)	21,324
(Gain) Loss on Reorganization items, net	$ 1,469	$ (956,142)

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

You should read the following discussion and analysis in conjunction with our financial information and our consolidated financial statements and accompanying notes included in this report and our annual report on Form 10-K for the year ended December 31, 2016. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 51 of this report.

As discussed in Notes 11 and 12 to our condensed consolidated financial statements included in Item 1 of this report, the Company applied fresh start accounting upon emergence from bankruptcy on the Effective Date (defined below) which resulted in the Company becoming a new entity for financial reporting purposes. The effects of the Plan (defined below) and the application of fresh-start accounting were reflected in our condensed consolidated financial statements as of April 22, 2016 and the related adjustments thereto were recorded in our condensed consolidated statements of operations as reorganization items for the period April 1, 2016 to April 22, 2016 (predecessor). References to the Successor relate to the Company on and subsequent to the Effective Date. References to Predecessor refer to the Company prior to the Effective Date.

Company Overview

SilverBow Resources ("SilverBow," the "Company," or "we") is a growth oriented independent oil and gas company headquartered in Houston, Texas. The Company's strategy is focused on acquiring and developing assets in the Eagle Ford Shale located in South Texas. Being a committed and long-term operator in South Texas, the Company possesses a significant understanding of the reservoirs in the region. We leverage this competitive understanding to assemble high quality drilling inventory while continuously enhancing our operations to maximize returns on capital invested. We hold a large acreage position in Texas prospective for the Eagle Ford Shale. Natural gas production accounted for 82% of our volumetric production and 72% of our sales revenue, while oil accounted for 7% of our production and 16% of our sales revenue for the third quarter of 2017.

Significant Developments During the Third Quarter of 2017

- *Operational Activity:* The Company continues to optimize completion techniques in order to enhance well performance across its portfolio, including optimized landing points, frac designs, and the expanded use of scale inhibitors. The Company drilled five wells in the quarter, including three in Fasken and two in Artesia. The Company completed five wells in the third quarter, all in Artesia. This activity contributed to total average net production for the third quarter of 2017 of approximately 156 Mmcfe/d. Third quarter 2017 daily production levels represent growth of 7% sequentially over the second quarter levels and nearly 23% since the end of 2016, adjusted for fourth quarter 2016 asset divestitures.

  During the third quarter 2017, the Company announced results for its initial Oro Grande well in Southeast La Salle County, the NMC 1H well. The well had cumulative production of 941 Mmcfe after ninety producing days and is currently producing approximately 10.0 Mmcfe/d with roughly 5,700 psi of flowing tubing pressure. The Company anticipates holding this level of production flat for the first seven months before the well's initial decline. The well had a lateral length of 7,500 feet and utilized the Company's largest completion design to date of roughly 3,400 pounds of proppant per lateral foot. In addition, and subsequent to quarter-end, the Company drilled the NMC 2H well and expects to complete this well in the fourth quarter 2017 with plans to drill again in the area in early 2018.

  Also in the third quarter 2017, the Company drilled three new wells on a single pad in our Fasken property. This three well pad included one well targeting the Lower Eagle Ford and two wells targeting the Upper Eagle Ford. The Company is testing an optimized completion design in the Upper Eagle Ford wells with encouraging results thus far. In particular, the Fasken 63H well was drilled partially in the Upper and Lower Eagle Ford is currently tracking above the Company's 14 Bcf type curve. The average well costs for the most recent three well pad in Fasken was approximately $5.0 million compared to an average of $5.9 million in 2016.

  Finally, the Company also drilled two wells in Artesia and completed five in the third quarter 2017. The average drilling and completion costs for these two wells were $5.5 million. The Company is currently leasing acreage in the northern portion of Artesia to increase the amount of high quality inventory where future capital will be deployed.

- *2017 Operations & Capital Budget:* On November 6, 2017, the Company announced a revised full-year capital budget of $205 to $215 million compared to the previous capital budget of $190 million to $200 million. This increase in the capital budget reflects the Company's ongoing success in its strategic leasing program where the Company has added approximately 28,000 acres and 300 locations to its portfolio since the first quarter. The Company's activities for the balance of the year include an additional well in Oro Grande, an appraisal well in Uno Mas, as well as a six well pad in Fasken in late December. For the full year 2017, the Company plans on drilling 29 wells and completing 24 wells.

  The Company has drilled twelve wells in Fasken thus far in 2017, including ten wells in the Lower Eagle Ford and two wells in the Upper Eagle Ford. The average well costs for Fasken in 2017 is $5.1 million which compares favorably to our average cost of $5.9 million for Fasken in 2016.

  The Company returned to Artesia for the first time since 2013 in the second and third quarters to deploy the newest generation of drilling and completion technology. Earlier wells in this area were drilled without the benefit of processed and evaluated 3-D seismic, target window identification, and modern completion design tied to longer laterals. The Company has completed seven wells in northern Artesia year-to-date, with lateral lengths ranging from 6,000 feet to 11,000 feet in accordance with lease configurations. The average drilling costs of $2.0 million for the seven wells drilled in Artesia during the second and third quarters decreased 38% from our 2013 drilling campaign. Likewise, the average completion cost per stage of $0.1 million decreased 33% despite increasing proppant volumes by 62% compared to our average completions in 2013.

  In AWP, SilverBow completed two gas wells earlier in the year, the Bracken 21H and 22H, which utilized 300 foot frac stage spacing and 1,500 pounds of proppant per foot of lateral. The Company continues to optimize its development of the AWP area to provide higher recovery efficiencies and enhanced economic returns through reservoir pressure management practices and optimized spacing and drilling sequencing between parent and child wells. At a cumulative production of 750 Mmcfe, the Bracken 21H and 22H are demonstrating an average increase of 543 psi of surface pressure compared against our four 2016 wells drilled in the same area and at the same cumulative production. The Company continues to acquire partner's working interests and bolt-on acreage in this area to further enhance efficiencies and returns while leveraging existing infrastructure.

Effective July 31, 2017, the Company disposed of its Wheeler assets in South Texas. This package represented 117 wellbores in the Company's AWP Olmos area. The Company received net proceeds of $0.7 million and the buyer's assumption of approximately $0.5 million of plugging and abandonment liability.

- *2017 Cost Reduction Initiatives:* We continue to focus on cost efficient operations and have taken additional actions during the first nine months of 2017 to reduce operating and overhead costs. These initiatives include field staff reductions, intermittent production of marginal properties, disposition of uneconomic and higher cost properties, full utilization of existing facilities, elimination of redundant equipment and replacement of rental equipment with company-owned equipment. At the corporate level, we have also undergone additional staff reductions, reduced the square footage of leased office space and are taking additional steps to further reduce overhead costs.

Summary of 2017 Financial Results

- *Year-to-date 2017 revenue and net income:* The Company's oil and gas revenues were $137.2 million during the first nine months of 2017, compared to $43.0 million and $78.5 million in the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. Revenues were higher primarily due to overall higher commodity prices as well as higher natural gas production, partially offset by lower oil and NGL production. The Company's net income of $46.8 million for the first nine months of 2017 was primarily due to higher commodity prices along with lower operating expenses while our net income of $851.6 million in the period of January 1, 2016 through April 22, 2016 (predecessor) was primarily due to the gain on reorganization adjustments as part of our emergence from bankruptcy while the net loss of $149.2 million for the period of April 23, 2016 through September 30, 2016 (successor) is primarily due to lower commodity prices and production along with a $133.5 million non-cash write-down of our oil and gas properties.

- *2017 capital expenditures and plans:* The Company's capital expenditures on a cash flow basis were $141.6 million in the first nine months of 2017, compared to $24.5 million and $36.8 million in the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. Expenditures for the first nine months of 2017 were primarily driven by development activity at our Fasken, AWP, Artesia, and Oro Grande fields in the Eagle Ford. For the first nine months, we have drilled 22 wells and completed 19. These expenditures were funded with operating cash flows along with borrowings under our Credit Facility. The Company's full-year capital budget of $205 million to $215 million provides for drilling 29 wells and completing 24 wells. See "Significant Developments During the Third Quarter of 2017" for more details regarding our recent capital expenditures and full-year development plans.

- *Working capital and debt to capitalization ratio:* The Company had a working capital deficit of $33.4 million at September 30, 2017, and a deficit of $57.6 million at December 31, 2016. The working capital computation does not include available liquidity through our credit facility.

- *Cash Flows:* For the nine months ended September 30, 2017, the Company generated cash from operating activities of $67.1 million, which included a decrease of $2.4 million attributable to changes in working capital. Cash used for property additions was $141.6 million. This does not include $9.4 million attributable to a net increase of capital related payables and accrued costs. The Company's net borrowings on its line of credit were $52.0 million for this period. Additionally, for the nine months ended September 30, 2017 the Company received $39.2 million from financing activities in connection with its share purchase agreement for the Company's common stock.

  For the period of April 23, 2016 through September 30, 2016 (successor) the Company generated cash from operating activities of $29.4 million, of which $7.4 million was attributable to changes in working capital. Cash used for property additions was $36.8 million. This included $17.6 million attributable to net pay-down of capital related payables and accrued cost as the Company paid a significant portion of the well completion costs from earlier in the year during this period. The Company's net borrowings on its line of credit were $1.0 million for the period of April 23, 2016 through September 30, 2016 (successor).

  For the period of January 1, 2016 through April 22, 2016 (predecessor) (which included the impact of cash transactions occurring upon emergence from bankruptcy) the Company's operating cash flow deficit for this period was $41.5 million, of which $15.4 million was attributable to working capital changes. During this period the Company incurred $25.6 million in legal and professional fees related to its bankruptcy and reorganization activities. While the Company paid $24.5 million for capital activities, it received cash proceeds of $48.7 million from asset sales (primarily from the sales of properties in Central Louisiana) and received $75 million in proceeds from its DIP credit facility. The Company utilized $71.9 million to pay down the borrowings outstanding under its Credit Facility from $324.9 million to $253.0 million prior to emergence from bankruptcy. The remaining $253.0 million outstanding under the Credit Facility was refinanced with the Company's new credit facility. The Company also paid $10.4 million of interest during the period and $6.5 million of debt issuance costs associated with obtaining the new Credit Facility.

Emergence from Voluntary Reorganization under Chapter 11 Proceedings

On December 31, 2015, we and eight of our U.S. subsidiaries (the “Chapter 11 Subsidiaries”) filed voluntary petitions seeking relief under Chapter 11 of Title 11 of the U.S. Bankruptcy Code (the "Bankruptcy Code") in the U.S. Bankruptcy Court for the District of Delaware under the caption *In re Swift Energy Company, et al* (Case No. 15-12670). The Company and the Chapter 11 Subsidiaries received bankruptcy court confirmation of their joint plan of reorganization (the "Plan") on March 31, 2016, and subsequently emerged from bankruptcy on April 22, 2016 (the "Effective Date").

Effect of the Bankruptcy Proceedings. During the bankruptcy proceedings, the Company conducted normal business activities and was authorized to pay and has paid (subject to caps applicable to payments of certain pre-petition obligations) pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders and critical vendors, pre-petition amounts owed to pipeline owners that transport the Company's production, and funds belonging to third parties, including royalty holders and partners.

In addition, subject to certain specific exceptions under the Bankruptcy Code, the Chapter 11 filings automatically stayed most judicial or administrative actions against the Company and efforts by creditors to collect on or otherwise exercise rights or remedies with respect to pre-petition claims. As a result, we did not record interest expense on the Company’s senior notes for the period of January 1, 2016 through April 22, 2016 (predecessor). For that period, contractual interest on the senior notes totaled $21.6 million.

Plan of Reorganization. Pursuant to the Plan, the significant transactions that occurred upon emergence from bankruptcy were as follows:

- the approximately $906 million of indebtedness outstanding on account of the Company’s senior notes, the $75 million drawn under the Company's DIP Credit Agreement (described below and more fully described below) and certain other unsecured claims were exchanged for 88.5% of the post-emergence Company’s common stock;
- the lenders under the DIP Credit Agreement (more fully described below) received a backstop fee consisting of 7.5% of the post-emergence Company’s common stock which was not included in the 88.5% distributed to creditors;
- the Company’s pre-petition common stock was canceled and the current shareholders received 4% of the post-emergence Company’s common stock and warrants to purchase up to 30% of the reorganized Company's equity;
- the warrants (each for up to 15% of the reorganized Company's equity), are exercisable at prices that represent a substantial increase from the value at emergence, as follows:

Issue Date	Expiration Date	Shares	Strike Price
April 22, 2016	April 22, 2019	2,142,857	$80.00
April 22, 2016	April 22, 2020	2,142,857	$86.18

- claims of other creditors were paid in full in cash, reinstated or otherwise treated in a manner acceptable to the creditors;
- the Company entered into a registration rights agreement to provide customary registration rights to certain holders of the Company’s post-emergence common stock who, together with their affiliates received upon emergence 5% or more of the outstanding common stock of the Company;
- the Company sold (effective April 15, 2016) a portion of its interest in its Central Louisiana fields known as Burr Ferry and South Bearhead Creek to Texegy LLC, for net proceeds of approximately $46.9 million including deposits received prior to the closing date; and
- the Company's previous credit facility (the "Prior First Lien Credit Facility") was terminated and a new senior secured credit facility (the "Credit Facility") with an initial $320 million borrowing base was established. For more information please refer to Note 5 of the condensed consolidated financial statements included in Item 1 of this report.

In accordance with the Plan, the post-emergence Company’s new board of directors was initially to be made up of seven directors consisting of the Chief Executive Officer, two directors appointed by Strategic Value Partners LLC ("SVP"), a former holder of the Company’s senior notes, two directors appointed by other former holders of the Company’s senior notes, one independent director and one independent non-executive chairman of the Board. In addition, pursuant to the Plan, SVP and the other former holders of the Company’s senior notes were given certain continuing director nomination rights subject to minimum share ownership conditions.

DIP Credit Agreement. During the bankruptcy, the DIP Credit Agreement provided for a multi-draw term loan of up to $75.0 million, which became available to the Company upon the satisfaction of certain milestones and contingencies. Upon emergence from bankruptcy, the Company had drawn down the entire $75.0 million available. Pursuant to the Plan, the borrowings under the DIP Credit Agreement, at the option of the lenders to the DIP Credit Agreement, converted into the post-emergence Company’s common stock, which was part of the 88.5% of the common stock distributed to the holders of the Company's senior notes and certain unsecured creditors. As such, the $75.0 million borrowed under the DIP Credit Agreement was not required to be repaid in cash and terminated upon the Company’s exit from bankruptcy. For more information please refer to Note 5 of the condensed consolidated financial statements included in Item 1 of this report.

Fresh Start Accounting. Upon the Company’s emergence from Chapter 11 bankruptcy, the Company adopted fresh-start accounting in accordance with the provisions of Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 852, "Reorganizations" which resulted in the Company becoming a new entity for financial reporting purposes. Upon adoption of fresh start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date. The Effective Date fair values of our assets and liabilities differed materially from the recorded values of our assets and liabilities as reflected in our historical condensed consolidated balance sheet. The effects of the Plan and the application of fresh-start accounting were reflected in our condensed consolidated financial statements as of April 22, 2016 and the related adjustments thereto were recorded in our condensed consolidated statements of operations as reorganization items for the period April 1, 2016 to April 22, 2016 (predecessor).

As a result, our condensed consolidated balance sheets and condensed consolidated statement of operations subsequent to the Effective Date will not be comparable to our condensed consolidated balance sheets and statements of operations prior to the Effective Date. Our condensed consolidated financial statements and related footnotes are presented with a black line division which delineates the lack of comparability between amounts presented on or after April 22, 2016 and dates prior. Our financial results for future periods following the application of fresh-start accounting will be different from historical trends and the differences may be material.

Financial Statement Classification of Liabilities Subject to Compromise. Our historical financial statements for periods prior to the Effective Date included amounts classified as liabilities subject to compromise, a majority of which were equitized upon emergence from bankruptcy on April 22, 2016. See Note 12 of the condensed consolidated financial statements included in Item 1 of this report for more information.

Liquidity and Capital Resources

Our primary use of cash flow has been to fund capital expenditures used to develop our oil and gas properties. Upon emergence from bankruptcy, our primary sources of liquidity are cash flows from operations and borrowings under the Credit Facility. Other potential sources of liquidity in the next twelve months include proceeds from sales of debt or equity securities. As of September 30, 2017, the Company's liquidity consisted of approximately $12.9 million of cash-on-hand and $77.1 million in available borrowings (calculated as $80 million of borrowing availability less $2.9 million in letters of credit) on the $330 million borrowing base under our Credit Facility. The Company is currently in the process of its Fall borrowing base redetermination, the preliminary commitments of which provide for a $40 million increase in the borrowing base from $330 million to $370 million. Management believes the Company has sufficient liquidity to meet both short-term and long-term obligations.

Revolving Credit Facility and Prior First Lien Credit Agreement. Upon our emergence from bankruptcy, the Prior First Lien Credit Agreement was terminated and paid in full, and the Company entered into a Senior Secured Revolving Credit Agreement among the Company, as borrower, JPMorgan Chase Bank, National Association, as administrative agent, and certain lenders party thereto. On April 19, 2017, the Company amended and restated the Senior Secured Revolving Credit Agreement by entering into a First Amended and Restated Senior Secured Revolving Credit Agreement (the "Credit Agreement") among the Company, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain lenders that are a party thereto, which provides for revolving loans of up to the borrowing base then in effect (the "Credit Facility"). The Credit Facility matures April 19, 2022. The maximum credit amount under the Credit Facility is currently $600 million with an initial borrowing base of $330 million. The borrowing base is scheduled to be redetermined in May and November of each calendar year, commencing November 2017, and is subject to additional adjustments from time to time, including for asset sales, elimination or reduction of hedge positions and incurrence of other debt. Additionally, each of the Company and the administrative agent may request an unscheduled redetermination of the borrowing base between scheduled redeterminations. The amount of the borrowing base is determined by the lenders in their discretion and consistent with their oil and gas lending criteria at the time of the relevant redetermination. The Company may also request the issuance of letters of credit under the Credit Agreement in an aggregate amount up to $25 million, which reduce the amount of available borrowings under the borrowing base in the amount of such issued and outstanding letters of credit.

Interest under the Credit Facility accrues at the Company's option either at an Alternative Base Rate plus the applicable margin ("ABR Loans") or the LIBOR Rate plus the applicable margin ("Eurodollar Loans"). The applicable margin ranges from 1.75% to 2.75% for ABR Loans and 2.75% to 3.75% for Eurodollar Loans. The Alternate Base Rate and LIBOR Rate are defined, and the applicable margins are set forth, in the Credit Agreement. Undrawn amounts under the Credit Facility are subject to a 0.50% commitment fee. To the extent that a payment default exists and is continuing, all amounts outstanding under the Credit Facility will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto.

The obligations under the Credit Agreement are secured, subject to certain exceptions, by a first priority lien on substantially all assets of the Company and certain of its subsidiaries, including a first priority lien on properties attributed with at least 85% of estimated proved reserves of the Company and its subsidiaries.

The Credit Agreement contains the following financial covenants:

- a ratio of total debt to EBITDA, as defined in the Credit Agreement, for the most recently completed four fiscal quarters, not to exceed 4.0 to 1.0 as of the last day of each fiscal quarter; and

- a current ratio, as defined in the Credit Agreement and which includes in the numerator available borrowings undrawn under the borrowing base, of not less than 1.0 to 1.0 as of the last day of each fiscal quarter.

Additionally, the Credit Agreement contains certain representations, warranties and covenants, including but not limited to, limitations on incurring debt and liens, limitations on making certain restricted payments, limitations on investments, limitations on asset sales and hedge unwinds, limitations on transactions with affiliates and limitation on modifying organizational documents and material contracts. The Credit Agreement contains customary events of default. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Credit Facility to be immediately due and payable.

We are in compliance with the covenants as of September 30, 2017 and expect to be in compliance with the covenants under the Credit Agreement during the next twelve months. Maintaining or increasing our conforming borrowing base under our Credit Facility is dependent upon many factors, including commodities pricing, our hedge positions and our ability to raise capital to drill wells to replace produced reserves.

Contractual Commitments and Obligations

In the ordinary course of business, we are party to various legal actions, which arise primarily from our activities as operator of oil and natural gas wells. We do not believe that any of these claims and actions, separately or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations, or cash flows, although we cannot guarantee that a material adverse effect will not occur.

We had no material changes in our contractual commitments during the nine months ended September 30, 2017 (successor) from our Annual Report on Form 10-K for the year ended December 31, 2016.

Off-Balance Sheet Arrangements

As of September 30, 2017, we had no off-balance sheet arrangements requiring disclosure pursuant to article 303(a) of Regulation S-K. We had no material changes in our contractual commitments and obligations from amounts referenced under "Contractual Commitments and Obligations" in Management's Discussion and Analysis in our Annual Report on Form 10-K for the year ended December 31, 2016.

Results of Operations

Revenues — Three Months Ended September 30, 2017 and Three Months Ended September 30, 2016

Natural gas production was 82% and 78% of our production volumes for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively. Natural gas sales were 72% and 65% of oil and gas sales for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively.

Crude oil production was 7% and 12% of our production volumes for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively. Crude oil sales were 16% and 26% of oil and gas sales for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively.

NGL production was 11% and 10% of our production volumes for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively. NGL sales were 12% and 9% of oil and gas sales for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively.

The following tables provide additional information regarding our oil and gas sales, by area, excluding any effects of our hedging activities, for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor):

Fields	Three Months Ended September 30, 2017 (Successor)		Three Months Ended September 30, 2016 (Successor)	
	Oil and Gas Sales (In Millions)	Net Oil and Gas Production Volumes (MMcfe)	Oil and Gas Sales (In Millions)	Net Oil and Gas Production Volumes (MMcfe)
Artesia Wells	$ 8.9	2,060	$ 3.6	1,050
AWP	13.0	3,185	15.7	4,302
Fasken	25.2	8,421	22.7	8,328
Other [(1)]	1.9	680	6.0	1,100
Total	$ 49.0	14,346	$ 48.0	14,780

(1) 2016 information composed primarily of fields sold during the year including our former Lake Washington, South Bearhead Creek and Burr Ferry Fields.

The sales volumes decrease from 2016 to 2017 was primarily due to decreased production due to natural declines, reduced drilling and completion activity and strategic dispositions of our non-core fields during 2016.

The following table provides additional information regarding our oil and gas sales, by commodity type, as well as the effects of our hedging activities for derivative contracts held to settlement, for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor) (in thousands, except per-dollar amounts):

	Three Months Ended September 30, 2017 (Successor)	Three Months Ended September 30, 2016 (Successor)
Production volumes:		
Oil (MBbl) [(1)]	170	293
Natural gas (MMcf)	11,723	11,494
Natural gas liquids (MBbl) [(1)]	267	255
Total (MMcfe)	14,346	14,780
Oil, Natural gas and Natural gas liquids sales:		
Oil	$ 7,996	$ 12,664
Natural gas	35,242	31,120
Natural gas liquids	5,780	4,176
Total	$ 49,019	$ 47,959
Average realized price:		
Oil	$ 46.93	$ 43.27
Natural gas	3.01	2.71
Natural gas liquids	21.67	16.38
Total	$ 3.42	$ 3.24
Price impact of cash-settled derivatives:		
Oil	$ (0.02)	$ 1.63
Natural gas	(0.01)	(0.12)
Natural gas liquids	—	—
Total	$ (0.01)	$ (0.06)
Average realized price including cash settled derivatives:		
Oil	$ 46.91	$ 44.91
Natural gas	3.00	2.58
Natural gas liquids	21.67	16.38
Total	$ 3.41	$ 3.18

(1) Oil and natural gas liquids are converted at the rate of one barrel of oil equivalent to six Mcfe

For the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor) the Company recorded net losses of $1.6 million and net gains of $2.6 million from our derivative activities, respectively. Hedging activity is recorded in “Net gain (loss) on commodity derivatives” on the accompanying condensed consolidated statements of operations.

Costs and Expenses — Three Months Ended September 30, 2017 and Three Months Ended September 30, 2016

The following table provides additional information regarding our expenses for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor):

Costs and Expenses	Three Months Ended September 30, 2017 (Successor)	Three Months Ended September 30, 2016 (Successor)
General and administrative, net	$ 6,031	$ 11,691
Depreciation, depletion, and amortization	11,832	13,287
Accretion of asset retirement obligation	582	1,099
Lease operating cost	5,831	9,481
Transportation and gas processing	4,921	4,883
Severance and other taxes	2,479	2,683
Interest expense, net	2,868	5,880
Reorganization items, net	—	1,193
Total Costs and Expenses	$ 34,544	$ 50,197

General and Administrative Expenses, Net. These expenses on a per Mcfe basis were $0.42 and $0.79 for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively. The decrease was primarily due to lower salaries and burdens, lower equity compensation and lower office rent, partially offset by a lower capitalization rate. Included in general and administrative expenses is $1.4 million and $2.9 million in share based compensation for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor).

Depreciation, Depletion and Amortization ("DD&A"). These expenses on a per Mcfe basis were $0.82 and $0.90 for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively. The lower depletion expense is due to a lower depletion rate due to higher reserves, offset in part by a higher depletable base.

Lease operating cost. These expenses on a per Mcfe basis were $0.41 and $0.64 for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively. The decrease per Mcfe was primarily due to a concentrated effort to reduce overall operating costs as well as divestitures of non-core assets in 2016.

Transportation and gas processing. These expenses all related to natural gas and NGL sales. These expenses per Mcf of natural gas sales were $0.42 for both the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor).

Severance and Other Taxes. These expenses on a per Mcfe basis were $0.17 and $0.18 for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively. Severance and other taxes, as a percentage of oil and gas sales, were approximately 5.1% and 5.6% for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively.

Interest. Our gross interest cost was $3.0 million and $6.1 million for the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor), respectively. The decrease in gross interest cost is primarily due to decreased borrowing rates as the Company terminated the non-conforming borrowing base on its Credit Facility in the second quarter of 2017. Interest cost of $0.2 million and $0.3 million was capitalized in the third quarters of 2017 and 2016, respectively. Upon emergence from bankruptcy, our only interest bearing debt is our Credit Facility.

Income Taxes. There was no expense for income taxes in the three months ended September 30, 2017 (successor) and three months ended September 30, 2016 (successor) as the Company has sufficient deferred tax carryover assets to offset the income during these periods.

Revenues — Nine Months Ended September 30, 2017 and Nine Months Ended September 30, 2016

The tables included below set forth financial information for the period of April 23, 2016 through September 30, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor) which are distinct reporting periods as a result of our emergence from bankruptcy on April 22, 2016.

Natural gas production was 83%, 68% and 76% of our production volumes for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. Natural gas sales were 74%, 52% and 60% of oil and gas sales for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively.

Crude oil production was 7%, 19% and 13% of our production volumes for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. Crude oil sales were 16%, 38% and 30% of oil and gas sales for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively.

NGL production was 10%, 13% and 11% of our production volumes for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. NGL sales were 10% of oil and gas sales for the nine months ended September 30, 2017 (successor) and 10% for both the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor).

The following tables provide additional information regarding our oil and gas sales, by area, excluding any effects of our hedging activities, for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor):

Fields	**Nine Months Ended September 30, 2017 (Successor)**		**April 23 - September, 30 2016 (Successor)**		**January 1 - April 22, 2016 (Predecessor)**	
	Oil and Gas Sales (In Millions)	**Net Oil and Gas Production Volumes (MMcfe)**	**Oil and Gas Sales (In Millions)**	**Net Oil and Gas Production Volumes (MMcfe)**	**Oil and Gas Sales (In Millions)**	**Net Oil and Gas Production Volumes (MMcfe)**
Artesia Wells	$ 16.8	4,023	$ 6.1	1,896	$ 3.5	1,542
AWP	40.8	9,821	27.1	8,058	14.7	5,706
Fasken	77.2	25,151	33.5	13,908	14.3	7,278
Other (1)	2.4	838	11.8	1,979	10.5	2,316
Total	$ 137.2	39,833	$ 78.5	25,841	$ 43.0	16,842

(1) 2016 information composed primarily of fields sold during the year including our former Lake Washington, South Bearhead Creek and Burr Ferry Fields.

The sales volumes decrease from 2016 to 2017 was primarily due to strategic dispositions of our non-core fields during 2016.

The following table provides additional information regarding our oil and gas sales, by commodity type, as well as the effects of our hedging activities for derivative contracts held to settlement, for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor) (in thousands, except per-dollar amounts):

	Nine Months Ended September 30, 2017 (Successor)	April 23 - September, 30 2016 (Successor)	January 1 - April 22, 2016 (Predecessor)
Production volumes:			
Oil (MBbl) (1)	456	546	522
Natural gas (MMcf)	32,904	19,558	11,431
Natural gas liquids (MBbl) (1)	699	501	380
Total (MMcfe)	39,833	25,841	16,842
Oil, Natural gas and Natural gas liquids sales:			
Oil	$ 21,724	$ 23,910	$ 16,413
Natural gas	101,349	46,974	22,423
Natural gas liquids	14,143	7,655	4,190
Total	$ 137,216	$ 78,540	$ 43,027
Average realized price:			
Oil	$ 47.64	$ 43.77	$ 31.43
Natural gas	3.08	2.40	1.96
Natural gas liquids	20.24	15.28	11.04
Total	$ 3.44	$ 3.04	$ 2.55
Price impact of cash-settled derivatives:			
Oil	$ (0.94)	$ 0.88	$ —
Natural gas	(0.06)	(0.07)	—
Natural gas liquids	—	—	—
Total	$ (0.05)	$ (0.04)	$ —
Average realized price including cash settled derivatives:			
Oil	$ 46.70	$ 44.65	$ 31.43
Natural gas	3.02	2.33	1.96
Natural gas liquids	20.24	15.28	11.04
Total	$ 3.39	$ 3.00	$ 2.55

(1) Oil and natural gas liquids are converted at the rate of one barrel of oil equivalent to six Mcfe

For the nine months ended September 30, 2017 (successor) and the period of April 23, 2016 through September 30, 2016 (successor), the Company recorded $14.5 million of net gains and $7.3 million of net losses from our derivative activities, respectively. For the period of January 1, 2016 through April 22, 2016 (predecessor) there were no net gains or losses from our derivative activities as all hedges under the predecessor Company had settled as of December 31, 2015. Hedging activity is recorded in “Net gain (loss) on commodity derivatives” on the accompanying condensed consolidated statements of operations.

Costs and Expenses — Nine Months Ended September 30, 2017 and Nine Months Ended September 30, 2016

The following table provides additional information regarding our expenses for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor):

Costs and Expenses	Nine Months Ended September 30, 2017 (Successor)	April 23 - September 30, 2016 (Successor)	January 1 - April 22, 2016 (Predecessor)
General and administrative, net	$ 22,676	$ 15,919	$ 9,245
Depreciation, depletion, and amortization	32,375	26,621	20,439
Accretion of asset retirement obligation	1,722	1,931	1,610
Lease operating cost	16,380	17,262	14,933
Transportation and gas processing	14,067	9,069	6,090
Severance and other taxes	6,377	4,547	3,917
Interest expense, net	11,117	10,137	13,347
Write-down of oil and gas properties	—	133,496	77,732
Reorganization items, net	—	1,469	(956,142)
Total Costs and Expenses	$ 104,714	$ 220,451	$ (808,829)

General and Administrative Expenses, Net. These expenses on a per Mcfe basis were $0.57, $0.55 and $0.62 for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. Included in general and administrative expenses is $4.5 million, $0.9 million and $3.1 million in share based compensation for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively.

Depreciation, Depletion and Amortization ("DD&A"). These expenses on a per Mcfe basis were $0.81, $1.21 and $1.03 for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. The depletion expense recorded in the period of January 1, 2016 through April 22, 2016 (predecessor) is not comparable against the successor periods due to the restatement of assets at their fair value upon emergence from bankruptcy. The lower depletion rate for the nine months ended September 30, 2017 (successor) when compared against the period of April 23, 2016 through September 30, 2016 (successor) is due primarily to higher reserves, offset in part by a higher depletable base.

Lease operating cost. These expenses on a per Mcfe basis were $0.41, $0.89 and $0.67 for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. The decrease per Mcfe was primarily due to a concentrated effort to reduce overall operating costs as well as divestitures of non-core areas in 2016.

Transportation and gas processing. These expenses all related to natural gas and NGL sales. These expenses per Mcf of natural gas sales were $0.43, $0.53 and $0.46 for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. The reduction was primarily attributable to improved negotiated rates for certain South Texas fields.

Severance and Other Taxes. These expenses on a per Mcfe basis were $0.16, $0.23 and $0.18 for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. Severance and other taxes, as a percentage of oil and gas sales, were approximately 4.6%, 9.1% and 5.8% for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. The decrease is primarily due to a shift in our production from Louisiana to Texas as a result of our dispositions in the prior year.

Interest. Our gross interest cost was $11.6 million, $13.3 million and $10.4 million for the nine months ended September 30, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through September 30, 2016 (successor), respectively. Interest costs of $0.5 million was capitalized in 2017, while there was $0.3 million capitalized interest in the period of April 23, 2016 through September 30, 2016 (successor). Upon emergence from bankruptcy, our only interest bearing debt is our Credit Facility.

Write-down of oil and gas properties. Primarily due to pricing differences between the 12-month average oil and gas prices used in the Ceiling Test and the forward strip prices used to estimate the initial fair value of oil and gas properties on the Company's April 22, 2016 (successor) balance sheet, we recorded a write-down of $133.5 million for the period of April 23, 2016 through September 30, 2016 (successor). Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, we recorded non-cash write-downs on a before-tax basis of $77.7 million for the period of January 1, 2016 through April 22, 2016 (predecessor).

Income Taxes. There was no expense for income taxes in the nine months ended September 30, 2017 as the Company has sufficient deferred tax carryover assets to offset the income during this period. The deferred tax assets are fully offset by valuation allowances. For 2016, the Company entered bankruptcy with Federal and state net operating loss carryovers and amortizable property basis significantly in excess of book value. This resulted in the Company having significant deferred tax assets. Given its history of incurring tax losses and economic uncertainty the Company recorded a full valuation allowance against these tax assets. The Company's emergence from bankruptcy resulted in a significant tax gain on the debt conversion to equity. The Company was able to fully offset this gain with its net operating losses. Since these operating losses carried a zero book balance after valuation allowances there was no tax expense realized as a result of the gain reported for the period of January 1, 2016 through April 22, 2016 (predecessor). The tax benefit for all loss periods is also offset with valuation allowances.

Non-GAAP Financial Measures

Adjusted EBITDA

We present adjusted EBITDA attributable to common stockholders ("Adjusted EBITDA") in addition to our reported net income (loss) in accordance with U.S. GAAP. Adjusted EBITDA is a non-GAAP financial measure that is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess our operating performance as compared to that of other companies in our industry, without regard to financing methods, capital structure or historical costs basis. It is also used to assess our ability to incur and service debt and fund capital expenditures. We define Adjusted EBITDA as net income (loss):

Plus/(Less):

- Depreciation, depletion, amortization;
- Accretion of asset retirement obligation;
- Interest expense;
- Impairment of oil and natural gas properties;
- Reorganization items;
- Net losses (gains) on commodity derivative contracts;
- Amounts collected (paid) for commodity derivative contracts held to settlement; and
- Share-based compensation expense.

Our Adjusted EBITDA should not be considered an alternative to net income (loss), operating income (loss), cash flows provided by (used in) operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

The following tables present reconciliations of our net income (loss) to Adjusted EBITDA for the periods indicated (in thousands):

	Successor	
	Three Months Ended September 30, 2017	**Three Months Ended September 30, 2016**
Net Income (Loss)	$ 12,884	$ 394
Plus:		
Depreciation, depletion and amortization	11,832	13,287
Accretion of asset retirement obligations	582	1,099
Interest expense	2,868	5,880
Impairment of oil and gas properties	—	—
Reorganization items	—	1,193
Derivative (gain)/loss	1,603	(2,603)
Derivative cash settlements collected/(paid) (1)	(63)	(957)
Share-based compensation expense	1,403	2,942
Adjusted EBITDA	$ 31,109	$ 21,235

(1) This includes accruals for settled contracts covering commodity deliveries during the period where the actual cash settlements occur outside of the period.

	Successor		Predecessor
	Nine Months Ended September 30, 2017	April 23, 2016 - September, 30 2016	January 1, 2016 - April 22, 2016
Net Income (Loss)	$ 46,834	$ (149,207)	$ 851,611
Plus:			
Depreciation, depletion and amortization	32,375	26,621	20,439
Accretion of asset retirement obligations	1,722	1,931	1,610
Interest expense	11,117	10,137	13,347
Impairment of oil and gas properties	—	133,496	77,732
Reorganization items	—	1,469	(956,142)
Derivative (gain)/loss	(14,465)	7,309	—
Derivative cash settlements collected/(paid) (1)	(2,352)	(957)	—
Share-based compensation expense	4,538	3,132	886
Adjusted EBITDA	$ 79,769	$ 33,931	$ 9,483

(1) This includes accruals for settled contracts covering commodity deliveries during the period where the actual cash settlements occur outside of the period.

Critical Accounting Policies and New Accounting Pronouncements

Fresh-start Accounting. Upon emergence from bankruptcy, we adopted fresh-start accounting, which resulted in the Company becoming a new entity for financial reporting purposes. Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date. The Effective Date fair values of our assets and liabilities differed materially from the recorded values of our assets and liabilities as reflected in our historical consolidated balance sheets. The effects of the Reorganization Plan and the application of fresh-start accounting were implemented as of April 22, 2016 and the related adjustments thereto were recorded in our condensed consolidated statement of operations as reorganization items for the period of January 1, 2016 through April 22, 2016.

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized including internal costs incurred that are directly related to these activities and which are not related to production, general corporate overhead, or similar activities. Future development costs are estimated on a property-by-property basis based on current economic conditions and are amortized to expense as our capitalized oil and natural gas property costs are amortized. We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method.

The costs of unproved properties not being amortized are assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. As these factors may change from period to period, our evaluation of these factors will change. Any impairment assessed is added to the cost of proved properties being amortized.

The calculation of the provision for DD&A requires us to use estimates related to quantities of proved oil and natural gas reserves and estimates of the impairment of unproved properties. The estimation process for both reserves and the impairment of unproved properties is subjective, and results may change over time based on current information and industry conditions. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test").

We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates.

If future capital expenditures outpace future discounted net cash flows in our reserve calculations, if we have significant declines in our oil and natural gas reserves volumes (which also reduces our estimate of discounted future net cash flows from proved oil and natural gas reserves) or if oil or natural gas prices decline, it is possible that non-cash write-downs of our oil and natural gas properties will occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties due to decreases in oil or natural gas prices.

New Accounting Pronouncements. In May 2014, the FASB issued ASU 2014-09, providing a comprehensive revenue recognition standard for contracts with customers that supersede current revenue recognition guidance. While our contract reviews are still in progress, we do not expect the adjustment, if any, to be material. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017.

The Company's revenues are substantially all attributable to oil and natural gas sales. Based on review of our most significant contracts, the Company believes the timing and presentation of revenues under ASU 2014-09 will be consistent with our current revenue recognition policy as described above with one probable exception. The Company currently uses the entitlement method of accounting when sales for our account are not in proportion to our ownership interest in production. To comply with ASU 2014-09, the Company expects to recognize revenue on the production sold for our account irrespective of ownership share of such production. Currently we do not have any significant imbalance situations; therefore, this is not expected to immediately impact our financial statements except for incremental disclosures. We are on track to finalize our contract reviews during the fourth quarter of 2017 and complete our implementation plans before year-end.

In February 2016, the FASB issued ASU 2016-02, which requires lessees to record most leases on the balance sheet. Under the new guidance, lease classification as either a finance lease or an operating lease will determine how lease-related revenue and expense are recognized. The guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years.

At December 31, 2016 the Company had lease commitments of approximately $8.8 million that it believes would be subject to capitalization under ASU 2016-02. This includes $1.9 million for our corporate office sub-lease which has a term of 4.4 years and commitments for equipment and vehicle leases which total $6.5 million. The Company did not incur any significant additional lease obligations during the first nine months of 2017. The equipment leases generally have original terms of 2 - 3 years. In some instances further analysis is needed to determine if renewal options would result in capitalized amounts in excess of the obligations during the primary lease term. Based on our preliminary assessment, we believe these leases would most likely be deemed to be operating leases under the new standard. The corporate office sub-lease is the only existing lease that extends beyond December 31, 2018. Management plans to adopt ASU 2016-02 in the quarter ending March 31, 2019. Management continuously evaluates the economics of leasing vs. purchase for operating equipment. The lease obligations that will be in place upon adoption of ASU 2016-02 may be significantly different than the current obligations. Accordingly, at this time we cannot estimate the amount that will be capitalized when this standard is adopted.

In August 2016, the FASB issued ASU 2016-15, which provides greater clarity to preparers on the treatment of eight specific items within an entity's statement of cash flows with the goal of reducing existing diversity on these items. The guidance is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. Early adoption is permitted, including adoption in an interim period. We are currently reviewing these new requirements. Implementation may result in presentation changes to our Statements of Cash Flows but we do not expect it to impact any of our other financial statements.

In January 2017, the FASB issued ASU 2017-01, to assist entities in evaluating whether transactions should be accounted for as an acquisition or disposal of an asset or business. 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, the set of transferred assets and activities are not a business. The guidance is effective for companies beginning January 1, 2018 with early adoption permitted. We are currently reviewing these new requirements to determine the impact of this guidance on our financial statements.

In May 2017, the FASB issued ASU 2017-09, which provides clarity on what changes to share-based payment awards are considered substantive and require modification accounting to be applied. The guidance is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those fiscal years. The Company does not expect ASU 2017-09 to have a significant impact on our financial statements or disclosures.

Forward-Looking Statements

This report includes forward-looking statements intended to qualify for the safe harbors from liability established by the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated production levels, reserve increases, capital expenditures, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words "could," "believe," "anticipate," "intend," "estimate," “budgeted”, "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- future cash flows and their adequacy to maintain our ongoing operations;
- oil and natural gas pricing expectations;
- liquidity, including our ability to satisfy our short- or long-term liquidity needs;
- business strategy, including our business strategy post-emergence from bankruptcy;
- estimated oil and natural gas reserves or the present value thereof;
- our borrowing capacity, future covenant compliance, cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- asset disposition efforts or the timing or outcome thereof;
- ongoing and prospective joint ventures, their structure and substance, and the likelihood of their finalization or the timing thereof;
- the amount, nature and timing of capital expenditures, including future development costs;
- timing, cost and amount of future production of oil and natural gas;
- availability of drilling and production equipment or availability of oil field labor;
- availability, cost and terms of capital;
- drilling of wells;
- availability and cost for transportation of oil and natural gas;
- costs of exploiting and developing our properties and conducting other operations;
- competition in the oil and natural gas industry;
- general economic conditions;
- opportunities to monetize assets;
- effectiveness of our risk management activities;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in world oil markets and in oil and natural gas-producing countries;
- uncertainty regarding our future operating results;
- plans, objectives, expectations and intentions contained in this report that are not historical;
- uncertainty of our ability to improve our operating structure, financial results and profitability following emergence from Chapter 11 and other risk and uncertainties related to our emergence from Chapter 11;
- 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 the current estimates in connection with the application of fresh start accounting; and
- other risks and uncertainties described in Part II, Item 1A. “Risk Factors,” in this quarterly report on Form 10-Q and our annual report on Form 10-K for the year ended December 31, 2016.

All forward-looking statements speak only as of the date they are made. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk Factors" in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2016. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

All subsequent written and oral forward-looking statements attributable to us or to persons acting on our behalf are expressly qualified in their entirety by the foregoing. We undertake no obligation to publicly release the results of any revisions to any such forward-looking statements that may be made to reflect events or circumstances after the date of this report or to reflect the occurrence of unanticipated events.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. This commodity pricing volatility has continued with unpredictable price swings in recent periods.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. As with our Prior First Lien Credit Agreement, we do not utilize these agreements and financial instruments for trading and only enter into derivative agreements with banks in our Credit Facility. For additional discussion related to our price-risk management policy, refer to Note 7 of our condensed consolidated financial statements included in Item 1 of this report.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. Continued volatility in both credit and commodity markets may reduce the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and when considered necessary, we also obtain letters of credit from certain customers, parent company guarantees if applicable, and other collateral as considered necessary to reduce risk of loss. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Concentration of Sales Risk. A large portion of our oil and gas sales are made to Kinder Morgan and its affiliates and we expect to continue this relationship in the future. We believe that the business risk of this relationship is mitigated by the reputation and nature of their business and the availability of other purchasers.

Interest Rate Risk. At September 30, 2017, we had $250 million drawn under our Credit Facility which has a floating rate of interest and therefore is susceptible to interest rate fluctuations.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act, consisting of controls and other procedures designed to give reasonable assurance that information we are required to disclose in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding such required disclosure. Our Chief Executive Officer and Chief Financial Officer have evaluated such disclosure controls and procedures as of the end of the period covered by this quarterly report on Form 10-Q and have determined that such disclosure controls and procedures are effective.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the three months ended September 30, 2017 (successor) that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

No material legal proceedings are pending other than ordinary, routine litigation incidental to the Company's business.

Item 1A. Risk Factors.

There have been no material changes in our risk factors disclosed in the 2016 Annual Report Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

None.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

The following exhibits in this index are required by Item 601 of Regulation S-K and are filed herewith or are incorporated herein by reference:

3.1	First Amended and Restated Certificate of Incorporation of SilverBow Resources, Inc., effective May 5, 2017 (incorporated by reference as Exhibit 3.1 to SilverBow Resources, Inc.'s Form 10-Q filed May 8, 2017, File No. 001-087541).
3.2	First Amended and Restated Bylaws of SilverBow Resources, Inc., effective May 5, 2017 (incorporated by reference as Exhibit 3.2 to SilverBow Resources, Inc.'s Form 10-Q filed May 8, 2017, File No. 001-08754).
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

*Filed herewith
+Management contract or compensatory plan or arrangement

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.

SILVERBOW RESOURCES, INC.
(Registrant)

Date:	November 7, 2017	By:	/s/ G. Gleeson Van Riet
			G. Gleeson Van Riet Executive Vice President and Chief Financial Officer
Date:	November 7, 2017	By:	/s/ Gary G. Buchta
			Gary G. Buchta Controller

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Sean C. Woolverton, certify that:

I have reviewed this Quarterly Report on Form 10-Q for the period ended September 30, 2017, of SilverBow Resources, Inc. (the "registrant");

1. 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;
2. 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;
3. 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 15(d)-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; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (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
4. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2017

/s/ Sean C. Woolverton
Sean C. Woolverton
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, G. Gleeson Van Riet, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the period ended September 30, 2017, of SilverBow Resources, Inc. (the “registrant”);
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 15(d)-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; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2017

/s/ G. Gleeson Van Riet
G. Gleeson Van Riet
Executive Vice President and
Chief Financial Officer

Exhibit 32

Certification of the Chief Executive Officer and Chief Financial Officer

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report on Form 10-Q for the period ended September 30, 2017 of SilverBow Resources, Inc. (the "Company") as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Sean C. Woolverton, the Chief Executive Officer of the Company, and G. Gleeson Van Riet, the Executive Vice President and Chief Financial Officer of the Company, each certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 7, 2017

/s/ Sean C. Woolverton

Sean C. Woolverton
Chief Executive Officer

Date: November 7, 2017

/s/ G. Gleeson Van Riet

G. Gleeson Van Riet
Executive Vice President and
Chief Financial Officer