Bonanza Creek Energy Announces Fourth Quarter and Full Year 2017 Financial and Operating Results

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- Quarterly GAAP cash flow from operating activities of $16.2 million; adjusted EBITDAX(1) of $21.6 million; GAAP net loss of $0.28 per diluted share; adjusted net income(1) of $0.40 per diluted share
- 2017 all-in finding and development costs of $7.46 per Boe
- Slick-water completion test is outperforming offset wells and expectations

(1) Non-GAAP measure, see attached Reconciliation Schedules.

DENVER, March 14, 2018 (GLOBE NEWSWIRE) -- Bonanza Creek Energy Inc. (NYSE:BCEI) (the "Company") today announces its fourth quarter and full year 2017 financial and operating results.

Fourth Quarter 2017 Results
For the fourth quarter of 2017, the Company reported quarterly and annual production volumes of 14.8 MBoe per day and 16.0 MBoe per day, respectively. As previously announced, these production figures exceeded the high end of the Company's guidance range. As the Company brought online new wells in the back half of the year, the product mix became increasingly oil-weighted as new wells with enhanced completions and choke management increased oil cuts. The oil-weighted growth from these wells along with increased commodity prices resulted in a 6% increase in quarterly revenues, despite the 19% decrease in production volumes from the prior year. The table below provides production data for the quarter and year ended December 31, 2017.

	Three Months Ended			Twelve Months Ended		
Avg. Daily Sales Volumes:	12/31/2017	12/31/2016	% Change	12/31/2017	12/31/2016	% Chang
Crude oil (Bbls/d)	8,350	9,058	(8)%	8,442	11,776	(28)%
Natural gas (Mcf/d)	22,176	29,664	(25)%	25,408	33,419	(24)%
Natural gas liquids (Bbls/d)	2,705	4,237	(36)%	3,319	4,336	(23)%
Crude oil equivalent (Boe/d)	14,750	18,239	(19)%	15,995	21,682	(26)%
Product Mix						
Crude oil	57 %	50 %		53 %	54 %	
Natural gas	25 %	27 %		26 %	26 %	
Natural gas liquids	18 %	23 %		21 %	20 %	
Average Sales Prices (before derivatives):						
Crude oil (per Bbl)	$ 52.00	$ 41.86	24%	$ 47.56	$ 35.31	35%
Natural gas (per Mcf)	$ 2.23	$ 2.32	(4)%	$ 2.39	$ 1.76	36%
Natural gas liquids (per Bbl)	$ 21.56	$ 14.40	50%	$ 18.06	$ 12.39	46%
Crude oil equivalent (per Boe)	$ 36.73	$ 27.90	32%	$ 32.65	$ 24.36	34%
Product Revenue (in thousands)	$ 49,850	$ 46,823	6%	$ 190,617	$ 193,335	(1)%

Upon emerging from bankruptcy, the Company focused on reducing operating expenses to right-size its cost structure with the current environment. The table below provides selected cash operating expenses comparatively on a quarterly and annual year-over-year basis.

	Three Months Ended	Twelve Months Ended

Operating Expenses	12/31/2017	12/31/2016	% Change	12/31/2017	12/31/2016	% Change
Lease operating expense	$ 10,066	$ 9,743	3%	$ 38,990	$ 43,671	(11)%
Gas plant and midstream operating expense	$ 3,314	$ 2,628	26%	$ 11,882	$ 12,826	(7)%
Severance and ad valorem taxes	$ 4,748	$ 3,773	26%	$ 15,261	$ 15,304	—%
General and Administrative	$ 11,356	$ 27,474	(59)%	$ 57,768	$ 77,065	(25)%

On an annual basis, the Company reduced its cash operating costs substantially as a result of various cost-saving measures that were implemented during 2017. While annual costs were reduced year over year, fourth quarter expenses increased compared to 2016. These increased costs resulted from increased well servicing expenses in the Mid-Continent region and implementation costs of compressor swaps that occurred in the Company's Rocky Mountain region. During the fourth quarter, the Company began a program to swap out existing compressors in the Wattenberg field to reduce its future rental fees. Compressor exchanges will continue into 2018 and the associated costs are reflected in the Company's lease operating expense guidance, provided on January 29, 2018. The Company expects its operating expenses to be reduced on a per-unit basis in 2018 as production volumes grow and field-level infrastructure capacity is optimally utilized.

The table below provides a regional breakout of the Company's lease operating expense and gas plant and midstream operating expenses.

Regional Breakout						
	Three Months Ended December 31, 2017					
	Rocky Mountain		Mid-Continent		Total Company	
	($M)	($/Boe)	($M)	($/Boe)	($M)	($/Boe)
Lease operating expense	$ 6,728	$ 6.11	$ 3,338	$ 13.04	$ 10,066	$ 7.42
Gas plant and midstream operating expense	1,802	1.64	1,512	5.90	3,314	2.44
Total	$ 8,530	$ 7.75	$ 4,850	$ 18.94	$ 13,380	$ 9.86

Reported net loss for the fourth quarter of 2017 was $5.8 million, or $0.28 per diluted share, compared to a net loss of $67.3 million, or $1.37 per diluted share, for the fourth quarter of 2016. Adjusted net income for the fourth quarter of 2017 was $8.3 million, or $0.40 per diluted share, compared to adjusted net loss of $27.9 million, or $0.57 per diluted share, for the fourth quarter of 2016. The increase in GAAP and adjusted net income over the prior year was driven by improved cost structure, greater oil-weighted production and an increase in commodity prices over the prior period.

Adjusted EBITDAX for the fourth quarter of 2017 was $21.6 million, a 49% increase compared to $14.5 million for the fourth quarter of 2016.

Adjusted net income (loss) and adjusted EBITDAX are non-GAAP financial measures. Please refer to the respective reconciliations in the schedules at the end of this release for additional information about these measures.

The table below summarizes the Company's annual results as compared to previously provided guidance.

Guidance vs Actual Summary			
	Twelve Months Ended December 31, 2017		
	Guidance	Actual	
Production (MBoe/d)	15.7 – 15.9	16.0	
Lease operating expense ($/Boe)	$6.50 – $7.00	$ 6.68	
Midstream ($/Boe)	$1.90 – $2.10	$ 2.04	
Cash G&A ($MM)*	$41 – $43	$ 44	
Production taxes (% of pre-derivative realization)	7% – 8%	8.0	%
CAPEX ($MM)	$108 – $115	$ 110	

* Cash G&A guidance is a non-GAAP measure that is exclusive of the Company's stock based compensation. The Company does not guide to GAAP G&A expense as it has excessive uncertainty due to the stock based compensation portion of GAAP G&A. Please refer to the non-GAAP disclosure at the end of this release for information regarding cash G&A.

The Company reported annual production above the high-end of guidance. With the exception of cash G&A, costs and capital were reported within the guided range. The Company's cash G&A expense for the year was above the high end of the Company's 2017 guidance range as a result of higher than expected advisory fees in the fourth quarter related to the previously proposed merger with SandRidge Energy, Inc.

2017 Proved Reserves, Costs Incurred, and Finding and Development Costs

As previously reported, Bonanza Creek's year-end 2017 proved reserves were 102.0 MMBoe, which represented a 13% increase from 2016. The Company's year-end 2017 proved reserves were comprised of 52.9 MMBbls of oil, 22.8 MMBbls of NGLs, and 157.7 Bcf of natural gas and were 53% proved developed. At year end the Company's proved reserves PV-10 utilizing SEC pricing was $598 million. If SEC pricing for oil and gas increased by 10% to $56.47 per barrel WTI and $3.28 per Mcf Henry Hub, the Company's proved reserves PV-10 would increase by 27% to $760 million. If, rather than flat pricing, 2017 year-end strip pricing is used, the Company's PV-10 value for its proved reserves would be $656 million. Please see Schedule 9 at the end of this release for information on SEC pricing and a reconciliation from PV-10 to the GAAP figure "Standardized Measure of Oil and Gas." All-in finding and development costs for 2017 were $7.46 per Boe, based on the Company's 2017 costs incurred of $127.5 million and all-in additions of 17,090 MBoe. A breakout of the Company's costs incurred are provided in the table below.

Costs Incurred

(in thousands)	For the Year Ended December 31, 2017	
Acquisition[1]	$	5,828
Development[2]		117,229
Exploration		4,440
Total[3]	$	127,497

(1) Acquisition costs for unproved properties were $5.8 million. There were no acquisition costs for proved properties in 2017.
(2) Development costs include workover costs of $6.1 million.
(3) Includes amounts relating to asset retirement obligations of $8.3 million.

Proved Reserve Roll-Forward

	MBoe	
Balance as of December 31, 2016	90,651	
Extensions, discoveries and infills	15,547	
Revisions to previous estimates	1,543	
Production	(5,719	)
Balance as of December 31, 2017	102,022	

2018 Production, Capital, and Expense Guidance
The table below reiterates the Company's previously provided 2018 guidance:

Guidance Summary

	Three Months Ended March 31, 2018	Twelve Months Ended December 31, 2018
Production (MBoe/d)	16.0 - 16.6	17.7 - 18.7

LOE ($/Boe)	$5.00 - $6.00
Midstream expense ($/Boe)	$1.40 - $1.80
Recurring cash G&A ($MM)(1)	$1.40 - $1.80
Production taxes (% of pre-derivative realization)	7% - 8%
Total CAPEX ($MM)	$280 - $320
Rockies Oil Differential (2)	$5.85 off WTI

(1) Recurring cash G&A guidance is a non-GAAP measure that is defined as GAAP G&A expense less stock based compensation and anticipated costs for permanent CEO compensation. The Company does not guide to GAAP G&A expense as it has excessive uncertainty due to the stock based compensation portion of GAAP G&A. Please refer to the Non-GAAP disclosure at the end of this release for information regarding Recurring cash G&A.

(2) Assumes strip pricing as of January 23, 2018.

Operational Update

During the fourth quarter, the Company turned online two adjacent pads in its central legacy acreage, the J21 and T21, which now have approximately 120 days of production data. These two pads consisted of a total of five wells, two SRL and three XRL, and tested an average of approximately 1,700 pounds of proppant per lateral foot. One of the SRL wells on the T21 pad utilized a slick-water completion design, which increased the fluid intensity by over 100%. While the wells on both of the pads are generally 5 performing in line with expectations, the one slick-water well on the T21 pad stands out with significant outperformance when compared to the other wells on these adjacent pads. The slick-water SRL that was tested in the central acreage is tracking the performance of the 500 MBoe per well average of the North Platte 44-13 pad on the Company's west acreage. The Company is very encouraged by the slick-water results and plans to test additional slick-water designs in the first half of the year in various portions of the Company's Wattenberg acreage.

At the beginning of 2018, the Company turned online its 8-SRL F26 pad, which utilized an average of approximately 2,000 pounds of proppant per lateral foot and has also recently turned online its first French Lake well. The Company is currently drilling its four XRL B-28 pad on its eastern acreage and is completing its remaining seven French Lake wells. These remaining French Lake wells are expected to be turned online by the end of the second quarter.

The Company has provided an updated investor presentation to its website, under the "For Investors" section of its corporate website at www.bonanzacrk.com. Included in this presentation are updated production results and corresponding type curves.

Fourth Quarter Earnings Release and Conference Call

The Company announces that in conjunction with this release of it fourth quarter 2017 operating and financial results, it will host a conference call to discuss these results on March 15, 2018 at 9:00 a.m. Mountain Time. A live webcast and replay of this event will be available on the Investor Relations section of the Company’s website at www.bonanzacrk.com. A dial-in replay of the event will be available through March 29, 2018. Dial-in information for the conference call is included below.

Type	Phone Number	Passcode
Live participant	877-793-4362	1899728
Replay	855-859-2056	1899728

About Bonanza Creek Energy, Inc.

Bonanza Creek Energy Inc. is an independent oil and natural gas company engaged in the acquisition, exploration, development and production of onshore oil and associated liquids-rich natural gas in the United States. The Company’s assets and operations are concentrated primarily in the Rocky Mountains in the Wattenberg Field, focused on the Niobrara and Codell formations, and in southern Arkansas, focused on oily Cotton Valley sands. The Company’s common shares are listed for trading on the NYSE under the symbol: “BCEI.” For more information about the Company, please visit www.bonanzacrk.com. Please note that the Company routinely posts important information about the Company under the Investor Relations section of its website.

Forward-Looking Statements

This press release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this press release that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. These statements are based on certain assumptions made by the Company based on management’s experience, perception of historical trends and technical analyses, current conditions, anticipated future developments and other factors believed to be appropriate and reasonable by management. When used in this press release, the words “will,” “potential,” “believe,” “estimate,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “plan,” “predict,” “project,” “profile,” “model” or their negatives, other similar expressions or the statements that include those words, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These statements include statements regarding development and completion expectations and strategy; and decreasing operating and capital costs. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, that may cause actual results to differ materially from those implied or expressed by the forward-looking statements, including the following: changes in natural gas, oil and NGL prices; general economic conditions, including the performance of financial markets and interest rates; drilling results; shortages of oilfield equipment, services and personnel; operating risks such as unexpected drilling conditions; ability to acquire adequate supplies of water; risks related to derivative instruments; access to adequate gathering systems and pipeline take-away capacity; and pipeline and refining capacity constraints. Further information on such assumptions, risks and uncertainties is available in the Company’s SEC filings. We refer you to the discussion of risk factors in our Annual Report on Form 10-K for the year ended December 31, 2017, filed on March 14, 2018, and other filings submitted by us to the Securities Exchange Commission. The Company’s SEC filings are available on the Company’s website at www.bonanzacrk.com and on the SEC’s website at www.sec.gov. All of the forward-looking statements made in this press release are qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, including guidance, and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

For further information, please contact:
James R. Edwards
Director - Investor Relations
720-440-6136
jedwards@bonanzacrk.com

Schedule 1: Statement of Operations
(in thousands, expect for per share amounts, unaudited)

	Successor Three Months Ended December 31, 2017	Pre Thr End 31,
Operating net revenues:		
Oil and gas sales	$ 50,189	$ 4
Operating expenses:		
Lease operating expense	10,066	9,7
Gas plant and midstream operating expense	3,314	2,6
Severance and ad valorem taxes	4,748	3,7
Exploration	3,386	3

Depreciation, depletion and amortization	9,126		26,
Abandonment and impairment of unproved properties	—		229
Unused commitments	—		4,2
Contract settlement expense	—		21,
General and administrative (including $1,035 and $1,643, respectively, of stock compensation)	11,356		27,
Total operating expenses	41,996		95,
Income (loss) from operations	8,193		(48
Other income (expense):			
Derivative gain (loss)	(12,603	)	490
Interest expense	(313	)	(15
Other income (loss)	(1,421	)	(3,5
Total other income (expense)	(14,337	)	(18
Loss from operations before taxes	(6,144	)	(67
Income tax benefit (expense)	376		&m
Net loss	$ (5,768	)	$
Net loss per basic common share	$ (0.28	)	$
Net loss per diluted common share	$ (0.28	)	$
Basic weighted-average common shares outstanding	20,454		49,
Diluted weighted-average common shares outstanding	20,454		49,

- The Predecessor Company followed the two-class method when computing the basic and diluted loss per share, which allocates earnings between common shareholders and unvested participating securities. The Successor Company follows the treasury stock method to compute basic and diluted net loss per share. Please refer to Note 14 – Earnings per Share in the Company's Annual Report on Form 10-K for the year ended December 31, 2017, for a detailed calculation.

	Successor April 29, 201 through December 3 2017
Operating net revenues:	
Oil and gas sales	$ 123,535
Operating expenses:	
Lease operating expense	25,862
Gas plant and midstream operating expense	8,341
Severance and ad valorem taxes	9,590
Exploration	3,745
Depreciation, depletion and amortization	21,312
Impairment of oil and gas properties	—
Abandonment and impairment of unproved properties	—
Unused commitments	—
Contract settlement expense	—
General and administrative (including $11,630, $2,116, and $8,892, respectively, of stock compensation)	42,676
Total operating expenses	111,526
Income (loss) from operations	12,009
Other income (expense):	
Derivative gain (loss)	(15,365
Interest expense	(773
Reorganization items, net	—
Gain on termination fee	—
Other income (loss)	(1,267
Total other income (expense)	(17,405

Income (loss) from operations before taxes	(5,396
Income tax benefit (expense)	376
Net income (loss)	$ (5,020
Net income (loss) per basic common share	$ (0.25
Net income (loss) per diluted common share	$ (0.25
Basic weighted-average common shares outstanding	20,427
Diluted weighted-average common shares outstanding	20,427

- The Predecessor Company followed the two-class method when computing the basic and diluted loss per share, which allocates earnings between common shareholders and unvested participating securities. The Successor Company follows the treasury stock method to compute basic and diluted net loss per share. Please refer to Note 14 – Earnings per Share in the Company's Annual Report on Form 10-K for the year ended December 31, 2017, for a detailed calculation.

Schedule 2: Statement of Cash Flows
(in thousands, unaudited)

	Successor		Predecesso
	Three Months Ended December 31, 2017		Three Mont Ended Dec 31, 2016
Cash flows from operating activities:			
Net loss	$ (5,768	)	$ (67,334
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	9,126		26,613
Abandonment and impairment of unproved properties	—		229
Well abandonment costs and dry hole expense	—		(33
Stock-based compensation	1,035		1,643
Amortization of deferred financing costs and debt premium	—		475
Derivative (gain) loss	12,603		(490
Derivative cash settlements	(1,464	)	2,584
Inventory write-off	1,758		4,390
Other	4		(450
Changes in current assets and liabilities:			
Accounts receivable	(2,450	)	5,840
Prepaid expenses and other assets	(1,899	)	(791
Accounts payable and accrued liabilities	3,441		11,636
Settlement of asset retirement obligations	(231	)	(327
Net cash provided by (used in) operating activities	16,155		(16,015
Cash flows from investing activities:			
Acquisition of oil and gas properties	(309	)	821
Exploration and development of oil and gas properties	(34,020	)	(4,853
(Increase) decrease in restricted cash	(4	)	5,094
Additions to property and equipment - non oil and gas	(207	)	(240
Net cash provided by (used in) investing activities	(34,540	)	822
Cash flows from financing activities:			
Payments to predecessor credit facility	—		(37,666
Payment of employee tax withholdings in exchange for the return of common stock	—		(6
Net cash provided by (used in) financing activities	—		(37,672
Net change in cash and cash equivalents	(18,385	)	(52,865

Cash and cash equivalents:		
Beginning of period	31,096	133,430
End of period	$ 12,711	$ 80,565

	Successor		Predece
	April 29, 2017 through December 31, 2017		January 2017 through April 28, 2017
Cash flows from operating activities:			
Net income (loss)	$ (5,020	)	$ 2,660
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	21,312		28,065
Non-cash reorganization items	—		(44,160
Impairment of oil and gas properties	—		&mdash
Abandonment and impairment of unproved properties	—		&mdash
Well abandonment costs dry hole expense	75		2,931
Stock-based compensation	11,630		2,116
Amortization of deferred financing costs and debt premium	—		374
Derivative (gain) loss	15,365		&mdash
Derivative cash settlements	(1,464	)	&mdash
Inventory write-off	1,758		&mdash
Other	11		18
Changes in current assets and liabilities:			
Accounts receivable	(4,477	)	(6,640
Prepaid expenses and other assets	(1,979	)	963
Accounts payable and accrued liabilities	(8,470	)	(5,880
Settlement of asset retirement obligations	(1,167	)	(331
Net cash provided by (used in) operating activities	27,574		(19,884
Cash flows from investing activities:			
Acquisition of oil and gas properties	(5,383	)	(445
Payments of contractual obligation	—		&mdash
Exploration and development of oil and gas properties	(76,375	)	(5,123
(Increase) decrease in restricted cash	(16	)	118
Additions to property and equipment - non oil and gas	(874	)	(454
Net cash used in investing activities	(82,648	)	(5,904
Cash flows from financing activities:			
Proceeds from predecessor credit facility	—		&mdash
Payments to predecessor credit facility	—		(191,667
Proceeds from sale of common stock	—		207,500
Payment of employee tax withholdings in exchange for the return of common stock	(2,398	)	(427
Deferred financing costs	—		&mdash
Net cash provided by (used in) financing activities	(2,398	)	15,406
Net change in cash and cash equivalents	(57,472	)	(10,382
Cash and cash equivalents:			
Beginning of period	70,183		80,565
End of period	$ 12,711		$ 70,183

Schedule 3: Balance Sheets
(in thousands, unaudited)

	Successo As of Decembe
ASSETS	
Current assets:	
Cash and cash equivalents	$ 12,71
Accounts receivable:	
Oil and gas sales	28,549
Joint interest and other	3,831
Prepaid expenses and other	6,555
Inventory of oilfield equipment	1,019
Derivative asset	488
Total current assets	53,153
Property and equipment (successful efforts method):	
Proved properties	555,341
Less: accumulated depreciation, depletion and amortization	(17,032
Total proved properties, net	538,309
Unproved properties	183,843
Wells in progress	47,224
Other property and equipment, net of accumulated depreciation of $2,224 in 2017 and $11,206 in 2016	4,706
Total property and equipment, net	774,082
Long-term derivative asset	6
Other noncurrent assets	3,130
Total assets	$ 830,3
LIABILITIES AND STOCKHOLDERS’ EQUITY	
Current liabilities:	
Accounts payable and accrued expenses	$ 62,12
Oil and gas revenue distribution payable	15,667
Derivative liability	11,423
Predecessor credit facility - current portion	—
Senior Notes - current portion	—
Total current liabilities	89,219
Long-term liabilities:	
Ad valorem taxes	11,584
Long-term derivative liability	2,972
Asset retirement obligations for oil and gas properties	38,262
Total liabilities	142,037
Commitments and contingencies	
Stockholders’ equity:	
Predecessor preferred stock, $.001 par value, 25,000,000 shares authorized, none outstanding as of December 31, 2016	—
Predecessor common stock, $.001 par value, 225,000,000 shares authorized, 49,660,683 issued and outstanding as of December 31, 2016	—
Successor preferred stock, $.01 par value, 25,000,000 shares authorized, none outstanding as of December 31, 2017	—
Successor common stock, $.01 par value, 225,000,000 shares authorized, 20,453,549 issued and outstanding as of December 31, 2017	4,286
Additional paid-in capital	689,068
Retained deficit	(5,020
Total stockholders’ equity	688,334
Total liabilities and stockholders’ equity	$ 830,3

Schedule 4: Volumes and Realized Prices (Before and After the Effect of Commodity Hedges) (unaudited)

	Three Months Ended December 31,	
	2017	2016
Wellhead Volumes and Prices		
Crude Oil and Condensate Sales Volumes (Bbl/d)		
Rocky Mountains	6,762	7,042
Mid-Continent	1,588	2,016
Total	8,350	9,058
Crude Oil and Condensate Realized Prices ($/Bbl)		
Rocky Mountains	$ 51.30	$ 39.98
Mid-Continent	54.95	48.44
Composite (before derivatives)	52.00	41.86
Composite (after derivatives)	50.06	44.96
Natural Gas Liquids Sales Volumes (Bbl/d)		
Rocky Mountains	2,311	3,695
Mid-Continent	394	542
Total	2,705	4,237
Natural Gas Liquids Realized Prices ($/Bbl)		
Rocky Mountains	$ 19.66	$ 13.19
Mid-Continent	32.72	22.65
Composite (before derivatives)	21.56	14.40
Composite (after derivatives)	21.56	14.40
Natural Gas Sales Volumes (Mcf/d)		
Rocky Mountains	17,397	23,061
Mid-Continent	4,779	6,603
Total	22,176	29,664
Natural Gas Realized Prices ($/Mcf)		
Rocky Mountains	$ 2.08	$ 2.12
Mid-Continent	2.77	3.01
Composite (before derivatives)	2.23	2.32
Composite (after derivatives)	2.24	2.32
Crude Oil Equivalent Sales Volumes (Boe/d)		
Rocky Mountains	11,972	14,581
Mid-Continent	2,778	3,658
Total	14,750	18,239
Crude Oil Equivalent Sales Prices ($/Boe)		
Rocky Mountains	$ 35.79	$ 26.01
Mid-Continent	40.81	35.47
Composite (before derivatives)	36.73	27.90
Composite (after derivatives)	35.66	29.44
Total Sales Volumes (MBoe)	1,357.0	1,678.0

Schedule 5: Per unit operating margins
(unaudited)

	For the Three Months Ended December 31,			For the Twelve Months Ended December 31,		
	2017	2016	Percent Change	2017	2016	Percent Change
Per Unit Costs ($/Boe)						

Realized price (before derivatives)	$ 36.73	$ 27.90	32%	$ 32.65	$ 24.36	34%
Lease operating expense	$ 7.42	$ 5.81	28%	$ 6.68	$ 5.50	21%
Midstream expense	$ 2.44	$ 1.57	55%	$ 2.04	$ 1.62	26%
Severance and Ad Valorem	$ 3.50	$ 2.25	56%	$ 2.61	$ 1.93	35%
Cash General and Administrative [1]	$ 7.61	$ 15.39	(51)%	$ 7.54	$ 8.59	(12)%
Total cash operating costs	$ 20.97	$ 25.02	(16)%	$ 18.87	$ 17.64	7%
Cash operating margin (before derivatives)	$ 15.76	$ 2.88	447%	$ 13.78	$ 6.72	105%
Derivative Cash Settlements	$ (1.07)	$ 1.54	(169)%	$ (0.25)	$ 2.31	(111)%
Cash operating margin (after derivatives)	$ 14.69	$ 4.42	232%	$ 13.53	$ 9.03	50%
Non-cash items						
Depreciation Depletion and Amortization	$ 6.72	$ 15.86	(58)%	$ 8.46	$ 14.01	(40)%
Non-cash General and Administrative	$ 0.76	$ 0.98	(22)%	$ 2.35	$ 1.12	110%

[1] Cash general and administrative expense excludes stock based compensation of $1.0 million and $1.6 million for the three-month periods ended December 31, 2017 and 2016, respectively, and $13.7 million and $8.9 million for the twelve-month periods ended December 31, 2017 and 2016, respectively.

Schedule 6: Adjusted Net Income (Loss)
(in thousands, except per share amounts, unaudited)

Adjusted net income (loss) is a supplemental non-GAAP financial measure that is used by management and external users of the Company’s consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. The Company defines adjusted net income (loss) as net income (loss) after adjusting first for (1) the impact of certain non-cash items, including unrealized gains and losses on unsettled derivative instruments, impairment of oil and gas properties, other similar non-cash charges (2) one-time transactions and then (3) the non-cash and one time items’ impact on taxes based on an applicable rate that approximates the Company's effective tax rate in each period. Adjusted net income (loss) is not a measure of net income (loss) as determined by GAAP.

The following table provides a reconciliation of net loss (GAAP) to adjusted net income (loss) (non-GAAP):

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
Net loss	$ (5,768)	$ (67,334)	$ (2,360)	$ (198,950)
Adjustments to net loss:				
Derivative (gain) loss	12,603	(490)	15,365	11,234
Derivative cash settlements	(1,464)	2,584	(1,464)	18,333
Impairment of proved properties	—	—	—	10,000
Abandonment and impairment of unproved properties	—	229	—	24,692
Exploratory dry hole expense	—	(33)	3,006	872
Stock-based compensation [1]	1,035	1,643	13,746	8,892
Advisor fees related to CEO transition and strategic alternatives [1]	2,774	14,457	2,774	20,375
Cash severance costs [1]	—	—	1,605	2,162
Pre-petition advisory fees[1]	—	—	683	—
Post-petition restructuring fees[1]	—	—	3,740	—
Reorganization items	—	—	(8,808)	—
Gain on termination fee	—	—	—	6,000
Contract settlement expense	—	21,000	—	21,000
Total adjustments before taxes	14,948	39,390	30,647	123,560
Income tax effect	(912)	—	(4,199)	—
Total adjustments after taxes	$ 14,036	$ 39,390	$ 26,448	$ 123,560
Adjusted net income (loss)	$ 8,268	$ (27,944)	$ 24,088	$ (75,390)
Adjusted net income (loss) per diluted share [2]	$ 0.40	$ (0.57)	$ 1.18	$ (1.53)

Diluted weighted-average common shares outstanding [2]	20,454	49,388	20,427	49,268

[1] Included as a portion of general and administrative expense on the consolidated statement of operations.

[2] For the twelve-month period ended December 31, 2017, the Company used the Successor's diluted weighted average share count to calculate adjusted net income per diluted share.

Schedule 7: Adjusted EBITDAX
(in thousands, except per share amounts, unaudited)

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of the Company’s consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. The Company defines adjusted EBITDAX as earnings before interest expense, income taxes, depreciation, depletion, amortization, impairment, exploration expenses and other similar non-cash and non-recurring charges. Adjusted EBITDAX is not a measure of net income or cash flows as determined by GAAP.

The following table presents a reconciliation of GAAP financial measures of net income (loss) to the non-GAAP financial measure of Adjusted EBITDAX.

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
Net Income (loss)	$ (5,768)	$ (67,334)	$ (2,360)	$ (198,950)
Exploration	3,386	3	7,444	946
Depreciation, depletion and amortization	9,126	26,613	49,377	111,215
Impairment of proved properties	—	—	—	10,000
Abandonment and impairment of unproved properties	—	229	—	24,692
Stock-based Compensation [1]	1,035	1,643	13,746	8,892
Cash severance costs [1]	—	—	1,605	2,162
Advisor fees related to CEO search and strategic alternatives[1]	2,774	14,457	2,774	20,375
Gain on termination fee	—	—	—	(6,000)
Contract settlement expense	—	21,000	—	21,000
Pre-petition advisory fees[1]	—	—	683	—
Post-petition restructuring fees[1]	—	—	3,740	—
Reorganization items	—	—	(8,808)	—
Interest expense	313	15,842	6,429	62,058
Derivative (gain) loss	12,603	(490)	15,365	11,234
Derivative cash settlements	(1,464)	2,584	(1,464)	18,333
Income tax (benefit) expense	(376)	—	(376)	—
Adjusted EBITDAX	$ 21,629	$ 14,547	$ 88,155	$ 85,957

[1] Included as a portion of general and administrative expense on the consolidated statement of operations.

Schedule 9: PV-10 of Estimated Proved Reserves

PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our proved oil and natural gas reserves.

The following table presents a reconciliation of GAAP Standardized Measure to the non-GAAP financial measure of PV-10.

(in thousands)	December 31, 2017
PV-10 [1]	598,498
Present value of future income taxes discounted at 10% [2]	—
Standardized Measure	$ 598,498

[1] The 12-month average benchmark pricing used to estimate SEC proved reserves and PV-10 value for crude oil and natural gas was $51.34 per Bbl of WTI crude oil and $2.98 per MMBtu of natural gas at Henry Hub before differential adjustments. Year-end 2017 benchmark prices for oil, and natural gas were both 20% higher from year-end 2016 SEC pricing. After differential adjustments, the Company's SEC pricing realizations for year-end 2017 were $46.76 per Bbl of oil, $19.57 per Bbl of NGLs, and $2.45 per Mcf of natural gas. Please refer to the Non-GAAP Disclosure at the end of this release for information regarding PV-10

[2] The tax basis of the Company's oil and gas properties as of December 31, 2017 provides more tax deduction than income generation when reserve estimates were prepared using 2017 SEC pricing.

Schedule 10: Cash G&A
(in thousands, unaudited)

Cash G&A is a supplemental non-GAAP financial measure that is used by management and external users of the Company’s consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. The Company defines cash G&A as GAAP general and administrative expense exclusive of the Company's stock based compensation and one-time charges, such as severance costs and advisor fees. The Company refers to cash G&A to provide typical cash G&A costs that are planned for in a given period. Cash G&A is not a fully inclusive measure of general and administrative expense as determined by GAAP.

The following table presents a reconciliation of GAAP financial measures of G&A expense to the non-GAAP financial measure of cash G&A.

	Three Months Ended		Twelve Months Ended	
	12/31/2017	9/30/2017	12/31/2017	12/31/2016
General and Administrative Expense	$ 11,356	$ 15,181	$ 57,768	$ 77,065
Stock Compensation	(1,035)	(2,646)	(13,746)	(8,892)
Cash G&A	10,321	12,535	44,022	68,173