Berry Petroleum Reports Fourth Quarter and Year End 2018 Results and Board Changes

March 7, 2019

DALLAS, March 06, 2019 (GLOBE NEWSWIRE) -- Berry Petroleum Corporation (NASDAQ: BRY) ("Berry" or the "Company") today reported net income attributable to common stockholders of $132 million, or $1.56 per diluted share, and adjusted net income of $35 million, or $0.41 per diluted share, for the fourth quarter of 2018. For the full year of 2018, Berry's net income attributable to common stockholders was $49 million, or $0.85 per diluted share, and adjusted net income was $100 million, or $1.26 per diluted share.

Highlights for the Quarter

- Adjusted EBITDA of $82 million and Unhedged Adjusted EBITDA of $73 million
- Capital Expenditures of $53 million with approximately 79% directed to development capital in California
- California production increased 11% over third quarter 2018
- Initiated share repurchase program with approximately 450,000 shares acquired in Q4 and nearly 2.4 million to date
- Completed divestiture of East Texas natural gas assets (approximately 0.7 MBoe/d) for $7 million
- Settlement of General Unsecured Stock Claims for 2.8 million shares of the 7.1 million initially reserved

Highlights for the Full Year

- Adjusted EBITDA of $258 million and Unhedged Adjusted EBITDA of $296 million
- Total company PV-10 increased by over $1.0 billion to $2.2 billion, including $2.0 billion for California
- Replaced 114% of total company reserves and 275% in California
- Capital Expenditures of $148 million with approximately 88% directed to development capital in California
- Drilled 224 wells in California to help grow production for California by 11% year over year
- Cash flows from operations of $230 million, which excludes $127 million for hedge early termination payment

Trem Smith, Berry President, Chief Executive Officer and Chairman of the Board stated, "Results for our fourth quarter and first full year of operations reinforce the new Berry story, namely how Berry's business model is simple and unique to the industry and why we are substantially different from the Berry of yesteryear. The idea of managing by growing value and returning capital to shareholders while living within free cash flow is not new to us - we do it now. It has been our strategy since Day One and we plan to continue to do it consistently through the complete commodity price cycle. The Berry of today is focused. We now only operate in three states, down from five at the time of emergence, and California is our area of greatest value creation as seen in our production and reserves growth as well as significant increase in value in 2018."

"As fiduciaries of the Company's capital program, we focused our capital on our best long-term value, California. We grew daily production in California by 11% year-over-year and confidently expect to grow in the mid-teens for 2019. Replacing our reserves in California by almost 275% just gives us more confidence in value remaining in our fields. We saw our total company reserves grow to 143 million Boe while the PV-10 improved by over $1 billion to $2.2 billion. We did this while living within free cash flow, paying a top tier dividend, and generating additional free cash."

"Our focus is on value through the cycle. Berry is capital efficient and doesn't have long-term drilling contracts that drive inefficiency. We can drill and move capital to where it provides the best long-term value and do it quickly. We are very flexible and responsive to changing market conditions. As a result, we have decreased our 2019 capital spending by $35 million or 14% with only a little more than 3% reduction in company-wide projected production. The technical knowledge gained over the last year and a half on our assets gives us a high level of confidence in the cash generating capability of these assets for many years to come. At Berry, we are excited about the value creation opportunities in 2019 and beyond."

Fourth Quarter 2018 Results

For the fourth quarter, Berry reported Adjusted EBITDA of $82 million, the same as the third quarter. Adjusted EBITDA, on an unhedged basis, was $73 million in the fourth quarter compared to $83 million in the third quarter, primarily due to lower oil prices, partially offset by increased production.

For the fourth quarter California oil prices before hedges averaged $62.65/Bbl which was 9% lower than the $69.13/Bbl realized in the third quarter. Realized oil prices for the Company before hedges of $61.48/Bbl were 9% lower than the third quarter.

Oil production averaged 23,700 barrels per day in the fourth quarter, while natural gas averaged 22,100 Mcf per day and NGLs averaged 600 barrels per day. California provided 21,700 Boe/d in the fourth quarter, an 11% increase over the third quarter, while the Rockies provided 5,800 Boe/d, down 19% from the third quarter due to continued marketing issues in Utah that impacted both sales and production. East Texas, the sale of which closed November 30, provided 700 Boe/d prior to the sale.

For the fourth quarter, Operating Expenses ("OpEx") totaled $48 million or $18.77/Boe compared to $46 million or $18.10/Boe in the third quarter. OpEx consists of lease operating expenses ("LOE"), as well as expenses and third-party revenues from electricity generation, transportation and marketing activities and the effect of derivative settlements (received or paid) for gas purchases while excluding taxes other than income taxes. The fourth quarter OpEx per Boe increase compared to the third quarter was primarily driven by higher fuel gas prices, reductions in electricity capacity payment revenues and changes in inventory costs in Utah, as well as the impact of selling our East Texas natural gas assets in November which had lower costs on a Boe basis compared to our other operations. We also mitigate a portion of our LOE with natural gas purchase hedges which offset a portion of the fourth quarter fuel costs.

General and administrative expenses were $16.1 million for the fourth quarter compared to $13.4 million for the third quarter largely due to an increase in stock compensation associated with performance shares meeting target thresholds. Adjusted general and administrative expenses were $11.5 million or $4.49/Boe for the fourth quarter compared to $10.7 million or $4.25/Boe for the third quarter. The quarter-over-quarter increases were primarily due to costs associated with supporting the Company's growth, public company status and the continued system improvements.

Taxes, other than income taxes were $7.8 million, or $3.05/Boe for the fourth quarter, compared to $8.3 million or $3.30/Boe in the third quarter, due to lower severance taxes associated with the lower production and rates where those taxes apply.

Capital expenditures totaled $53 million for the fourth quarter compared to $40 million for the third quarter, in both periods largely focused on drilling in California.

Adjusted net income was $35 million for the fourth quarter compared to $41 million for the third quarter of 2018. The decrease in adjusted net income was primarily associated with an increase in our corporate tax rate from 17% in the third quarter to 23% in the fourth quarter.

Full Year 2018 Results

Full year comparisons to 2017 present 2017 results as a single amount for simplicity, but represent two distinct periods, the two months ended February 28, 2017 (associated with our predecessor) and the ten months ended December 31, 2017 (our results as successor).

For 2018, Berry reported Adjusted EBITDA of $258 million compared to $178 million for 2017. Adjusted EBITDA, on an unhedged basis, was $296 million in 2018 compared to $175 million in 2017, primarily due to higher oil prices and increased oil production, as well as the increased percentage oil represents of our production in 2018 due to the acquisition of oil assets and disposal of gas assets in 2017.

For 2018, California oil prices before hedges averaged $65.64/Bbl which was 37% higher than the $47.79/Bbl realized in 2017. Realized oil prices for the Company before hedges of $64.76/Bbl were 35% higher than 2017.

Oil production averaged 22,000 barrels per day in 2018, natural gas averaged 26,300 Mcf per day and NGLs averaged 600 barrels per day. California provided 19,700 Boe/d in 2018, an 11% increase over 2017, while the Rockies provided 6,600 Boe/d, down 11% from 2017 due to continued marketing issues in Utah that impacted both sales and production. East Texas, the sale of which closed November 30, 2018 provided 700 Boe/d prior to the sale. Included in these year-over-year changes was the impact of the 2017 asset transactions which increased daily oil production in California by approximately 1,500 barrels and reduced gas production in the Rockies by 5,600 Boe.

For 2018 OpEx totaled $181 million or $18.33/Boe compared to $195 million or $16.84/Boe in 2017. The OpEx per Boe increase was primarily driven by a 25% increase in LOE per Boe from $15.32 per Boe in 2017 to $19.16 in 2018 largely due to the change in the mix of our products from 64% oil to 82% driven by the July 2017 asset transactions, as well as the oil production growth from capital expenditures during 2018. LOE increased due to higher fuel gas costs (mainly higher volumes purchased), and increased facility maintenance, and well servicing activity. The OpEx per Boe increase was partially offset by a decrease in transportation expense in 2018 primarily due to the disposition of gas assets in 2017, which required significant transportation.

General and administrative expenses were $54 million for 2018 compared to $64 million for 2017. The decrease in general and administrative expenses was due to reduced restructuring and transaction costs, partially offset by higher costs associated with building out a public company infrastructure including higher labor costs and the related increased stock compensation. Adjusted general and administrative expenses were $41 million or $4.13/Boe for 2018 compared to $32 million or $2.74/Boe for 2017. The increase in adjusted general and administrative expenses per Boe was due to increased costs associated with supporting the company's growth and public company status, as well as the impact of lower volumes noted above from the change in production mix resulting from the 2017 asset transactions.

Taxes, other than income taxes were $33 million, or $3.36/Boe for 2018, compared to $39 million or $3.40/Boe in 2017, due to reduced green house gas unit costs and lower severance taxes associated with the lower production and rates where those taxes apply.

Capital expenditures totaled $148 million for 2018 compared to $73 million for 2017. The increased capital was largely focused on increased drilling in California, which accounted for 88% of our development capital spent in 2018.

Adjusted net income was $100 million for 2018 compared to $28 million for 2017. The improved results in 2018 compared to 2017 reflected improved operating results, partially offset by an increased corporate tax rate.

As of December 31, 2018 our elected commitment under our reserves-based lending credit facility ("RBL Facility") was $400 million with no outstanding borrowings. We had $393 million available for borrowing under the RBL Facility due to outstanding letters of credit. The Company has current liquidity of $401 million including a cash balance of $10 million. For 2018 we generated levered free cash flow, as defined in "Non-GAAP Financial Measures and Reconciliations", of $46 million, or $84 million on an unhedged basis. During the fourth quarter we repurchased approximately 450,000 shares of Berry's common equity and almost 2.4 million shares to date.

"Our significant adjusted EBITDA in 2018 gave us the confidence to return meaningful capital to shareholders in the form of dividends, which we began in our first quarter as a public company, as well as through our share repurchase program, which we initiated in the fourth quarter. We have repurchased almost 2.4 million shares to date for approximately $25 million. We also issued the remaining common shares reserved for claims in connection with the bankruptcy. We issued only 2.8 million shares of the 7.1 million shares initially reserved," stated Cary Baetz, Chief Financial Officer. "In light of the continued challenging market in Utah and our constant focus on value, we have realigned our 2019 plans to focus almost all capital in California. Within California, we have reallocated the capital to areas which are less likely to be impacted by regulatory permitting delays. We have reduced planned capital spending by $35 million while reducing production projections by only a little more than 3%. We still see our California production growth in the mid-high teens in California, and we are still living out of our levered free cash flow at today's strip prices. Accordingly, we have updated our 2019 guidance. Beginning with this period, we will present our operating and financial results split between California and Rockies to provide better visibility to our operations and their value."

Full-Year 2019 Guidance

- Production between 28,000 to 31,000 Boe/d, approximately 86% oil
- OPEX ranging from $18.00 to $19.50 per Boe
- Taxes, other than income taxes, ranging from $4.25 to $4.75 per Boe
- Adjusted G&A ranging from $4.25 to $4.75 per Boe
- CapEx ranging from $195 million to $225 million
- CROIC[(a)] ranging from 18% to 24%

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(a) Cash Returned on Invested Capital ("CROIC") consists of net cash provided by operating activities before working capital, interest and non-recurring items, divided by the sum of average stockholders' equity and average debt.

Board of Directors Changes

As the Company previously announced, Donald Paul has been added to the board as an independent director. In addition, the board appointed Trem Smith, Berry Petroleum President and CEO, as Chairman of the Board. Smith replaces previous Chairman Brent Buckley in that position, effective February 28, 2019, with Buckley continuing to serve as a director.

Brent Buckley of Benefit Street Partners served as board chairman from June 2017 and helped lead the company out of bankruptcy to a successful IPO in July 2018. Smith stated "The company is profoundly grateful for the primary role Brent took in leading Berry out of bankruptcy two years ago and helping, as Board Chairman, prepare us to be a public company. I am honored to work with him and greatly appreciate his intensity and commitment to making Berry what it is today. We are pleased that Brent will remain a director and member of the Audit and Compensation Committees continuing to provide valuable guidance to the Board." Buckley noted, "I have always seen the potential of Berry's assets and capital structure offer. Now that we've successfully taken Berry public and have added a number of capable directors, it is time to transition some of my responsibilities on the Board. I look forward to continuing to work with the team and welcome the new directors."

Berry Petroleum added new board members Ms. Anne Marriuci and Mr. Kent Potter in September 2018. The addition of Donald Paul brings the total board membership to seven. Additionally, the company today announced Ms. Mariucci will assume the role of Lead Director for the Board further reflecting corporate best practices designed to ensure independent oversight of the company and its activities.

Earnings Conference Call

The Company will host a conference call March 7, 2019 to discuss these results:

Live Call Date:	Thursday, March 7, 2019
Live Call Time:	9:00 a.m. Eastern Time (6 a.m. Pacific Time)
Live Call Dial-in:	877-491-5169 from the U.S.
	720-405-2254 from international locations
Live Call Passcode:	7682805

A live audio webcast will be available on the "Investors" section of Berry's website at berrypetroleum.com/investors.

An audio replay will be available shortly after the broadcast:

Replay Dates:	Through Thursday, March 21, 2019
Replay Dial-in:	855-859-2056 from the U.S.
	404-537-3406 from international locations
Replay Passcode:	7682805

A replay of the audio webcast will also be archived on the "Investors" section of Berry's website at berrypetroleum.com/investors. In addition, an investor presentation will be available on the Company's website.

About Berry Petroleum

Berry Petroleum is a publicly-traded (NASDAQ: BRY) western United States independent upstream energy company with a focus on the conventional, long-lived oil reserves in the San Joaquin basin of California. More information can be found at the Company's website at berrypetroleum.com.

Forward Looking Statements

The information in this press release includes forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements specifically include our expectations as to our future

- financial position,
- liquidity,
- cash flows,
- results of operations and business strategy,
- potential acquisition opportunities,
- other plans and objectives for operations,
- maintenance capital requirements
- expected production and costs,

- reserves,
- hedging activities,
- capital expenditures
- return of capital
- improvement of recovery factors and other guidance.

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. Factors (but not necessarily all the factors) that could cause results to differ include:

- volatility of oil, natural gas and natural gas liquids prices;
- inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures and meet working capital requirements;
- price and availability of natural gas;
- our ability to use derivative instruments to manage commodity price risk;
- impact of environmental, health and safety, and other governmental regulations, and of current, pending or future legislation;
- uncertainties associated with estimating proved reserves and related future cash flows;
- our inability to replace our reserves through exploration and development activities;
- our ability to obtain permits and otherwise meet our proposed drilling schedule and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
- changes in tax laws;
- effects of competition;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- market fluctuations in electricity prices and the cost of steam; and
- other material risks that appear in the Risk Factors section of the prospectus filed with the SEC in connection with our initial public offering.

You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, continue, could, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes. We undertake no responsibility to publicly release the result of any revision of our forward-looking statements after the date they are made.

TABLES FOLLOWING

The financial information and certain other information presented in this Exhibit have been rounded to the nearest whole number or the nearest decimal. Therefore, the sum of the numbers in a column may not conform exactly to the total figure given for that column in certain tables. In addition, certain percentages presented here reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers, or may not sum due to rounding.

SUMMARY OF RESULTS

	Berry Corp. (Successor)					Berry LLC (Predecessor)
	Quarter Ended December 31, 2018	Quarter Ended September 30, 2018	Quarter Ended December 31, 2017	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
	($ and shares in thousands, except per share amounts)					
Consolidated Statement of Operations Data:						
Revenues and other:						
Oil, natural gas and natural gas liquids sales	$ 142,861	$ 147,004	$ 120,603	$ 552,874	$ 357,928	$ 74,120
Electricity sales	9,517	14,268	6,455	35,208	21,972	3,655
Gains (losses) on oil derivatives	127,160	(18,994)	(72,542)	(4,621)	(66,900)	12,886
Marketing revenues	534	486	793	2,322	2,694	633
Other revenues	274	183	73	774	3,975	1,424
Total revenues and other	280,346	142,947	55,382	586,557	319,669	92,718
Expenses and other:						

Lease operating expenses	51,308	51,649	44,586	188,776	149,599	28,238
Electricity generation expenses	6,764	6,130	4,701	20,619	14,894	3,197
Transportation expenses	2,220	2,318	593	9,860	19,238	6,194
Marketing expenses	716	437	645	2,140	2,320	653
General and administrative expenses	16,130	13,429	12,480	54,026	56,009	7,964
Depreciation, depletion, amortization and accretion	24,253	21,729	20,086	86,271	68,478	28,149
Taxes, other than income taxes	7,829	8,317	9,098	33,117	34,211	5,212
(Gains) losses on natural gas derivatives	(4,477)	(1,879)	—	(6,357)	—	—
(Gains) losses on sale of assets and other, net	(3,269)	400	(2,243)	(2,747)	(22,930)	(183)
Total expenses and other	101,474	102,530	89,946	385,705	321,819	79,424
Other income (expenses):						
Interest expense	(8,820)	(9,877)	(5,972)	(35,648)	(18,454)	(8,245)
Other, net	108	347	—	243	4,071	(63)
Total other income (expenses)	(8,712)	(9,530)	(5,972)	(35,405)	(14,383)	(8,308)
Reorganization items, net	1,498	13,781	(730)	24,690	(1,732)	(507,720)
Income (loss) before income taxes	171,658	44,668	(41,266)	190,137	(18,265)	(502,734)
Income tax expense (benefit)	39,890	7,683	(6,386)	43,035	2,803	230
Net income (loss)	131,768	36,985	(34,880)	147,102	(21,068)	$ (502,964)
Series A preferred stock dividends and conversion to common stock	—	(86,642)	(5,567)	(97,942)	(18,248)	n/a
Net income (loss) attributable to common stockholders	$ 131,768	$ (49,657)	$ (40,447)	$ 49,160	$ (39,316)	n/a
Net income (loss) per share attributable to common stockholders						
Basic[(a)]	$ 1.56	$ (0.70)	$ (1.05)	$ 0.85	$ (1.02)	n/a
Diluted[(a)]	$ 1.56	$ (0.70)	$ (1.05)	$ 0.85	$ (1.02)	n/a
Weighted-average common shares outstanding - basic[(a)]	84,367	70,940	38,644	57,743	38,644	n/a
Weighted-average common shares outstanding - diluted[(a)]	84,592	70,940	38,644	57,932	38,644	n/a
Adjusted net income (loss)[(b)]	$ 34,809	$ 40,529	$ 21,835	$ 100,001	$ 35,880	$ (7,779)
Adjusted EBITDA[(b)]	$ 81,669	$ 81,736	$ 52,840	$ 257,924	$ 149,613	$ 28,845
Adjusted EBITDA unhedged[(b)]	$ 72,990	$ 82,788	$ 59,674	$ 296,406	$ 146,545	$ 28,311
Levered free cash flow[(b)]	$ 9,531	$ 24,251	$ 35,425	$ 45,787	$ 44,948	$ 15,194
Levered free cash flow unhedged[(b)]	$ 852	$ 25,303	$ 42,259	$ 84,269	$ 41,880	$ 14,660
Adjusted general and administrative expenses[(b)] .	$ 11,533	$ 10,706	$ 8,659	$ 40,668	$ 23,865	$ 7,964

Effective Tax Rate	23 %	17 %	15 %	23 %	(15)%	0 %
Cash Flow Data:						
Net cash provided by (used in) operating activities[c]	$ 95,767	$ 56,880	$ 39,086	$ 103,100	$ 107,399	$ 22,431
Net cash provided by (used in) investing activities	$ (36,694)	$ (40,028)	$ (8,045)	$ (119,069)	$ (80,525)	$ (3,133)
Net cash provided by (used in) financing activities	$ (14,306)	$ (16,250)	$ (62)	$ 15,911	$ (43,170)	$ (162,668)

(a) Our weighted-average common shares outstanding increased beginning in the third quarter of 2018 for additional shares from our initial public offering and preferred stock conversion. We retrospectively adjusted for 2,770,000 shares issued instead of the 7,080,000 shares that were reserved for holders of allowed Unsecured Notes and General Unsecured Claims in our earnings per share calculations for the 2018 and 2017 Successor periods.

(b) See further discussion and reconciliation in “Non-GAAP Financial Measures and Reconciliations”.

(c) Year ended December 31, 2018 includes approximately $127 million paid to early terminate unsettled derivative contracts. The elective cancellation was effected to realign our hedging pricing with current market rates and move from NYMEX WTI to ICE Brent underlying. Had we not elected to cancel these derivative contracts our net cash provided by operating activities would have been approximately $230 million.

	Berry Corp. (Successor)	
	December 31, 2018	December 31, 2017
	($ and shares in thousands)	
Balance Sheet Data:		
Total current assets	$ 229,022	$ 137,524
Total property, plant and equipment, net	$ 1,442,708	$ 1,387,191
Total current liabilities	$ 144,118	$ 182,659
Long-term debt	$ 391,786	$ 379,000
Total equity	$ 1,006,446	$ 859,310
Outstanding common stock shares as of[d]	81,202	32,920

(d) Excludes 2,770,000 common stock shares negotiated with general unsecured creditors electing to settle claims in exchange for common shares subsequent to December 31, 2018. Also excludes 1,930,000 shares repurchased in our share repurchase program subsequent to December 31, 2018.

SUMMARY BY AREA

The following table shows a summary by area of our selected historical financial information and operating data for the periods indicated. Full year data for 2017 are presented as a single amount for simplicity, but represent two distinct periods, the two months ended February 28, 2017 (our predecessor) and the ten months ended December 31, 2017 (our successor).

	California (San Joaquin and Ventura basins)		Rockies (Uinta and Piceance basins)	
	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2018	Year Ended December 31, 2017
($ in thousands, except prices)				
Total revenues	$ 471,983	$ 311,247	$ 76,855	$ 76,365
Operating income[a]	$ 226,854	$ 74,629	$ 19,089	$ 9,961
Depreciation, depletion, and amortization	$ 72,260	$ 71,092	$ 11,066	$ 17,792
Average daily production (MBoe/d)	19.7	17.8	6.7	7.4
Production (oil% of total)	100 %	100 %	36 %	36 %
Realized prices:				
Oil (per Bbl)	$ 65.64	$ 47.79	$ 57.34	$ 48.47
NGLs (per Bbl)	$ —	$ —	$ 26.95	$ 21.36
Gas (per Mcf)	$ —	$ —	$ 2.71	$ 2.78
Capital expenditures	$ 125,565	$ 63,313	$ 17,351	$ 1,451
Total proved reserves (MMBoe)	106	93	37	46
PV-10[b]	$ 2,026,880	$ 998,391	$ 124,652	$ 108,375

(a) Operating income includes oil, natural gas and NGL sales, offset by operating expenses, general and administrative expenses, DD&A, and taxes, other than income taxes.

(b) PV-10 is a financial measure that is not calculated in accordance with GAAP. For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see “Non-GAAP Financial Measures and Reconciliations”.

COMMODITY PRICING

	Berry Corp. (Successor)					Berry LLC (Predecessor)
	Quarter Ended December 31, 2018	**Quarter Ended September 30, 2018**	**Quarter Ended December 31, 2017**	**Year Ended December 31, 2018**	**Ten Months Ended December 31, 2017**	**Two Months Ended February 28, 2017**
Realized Prices						
Oil without hedge ($/Bbl)	$ 61.48	$ 67.67	$ 54.77	$ 64.76	$ 48.05	$ 46.94
Effects of scheduled derivative settlements ($/Bbl)	$ 2.88	$ (0.51)	$ (3.37)	$ (5.09)	$ 0.48	$ 0.46
Oil with hedge ($/Bbl)	$ 64.36	$ 67.16	$ 51.40	$ 59.67	$ 48.53	$ 47.40
Natural gas ($/Mcf)	$ 3.86	$ 2.55	$ 2.75	$ 2.74	$ 2.70	$ 3.42
NGLs ($/Bbl)	$ 20.39	$ 37.75	$ 28.15	$ 26.74	$ 22.23	$ 18.20
Index Prices						
Brent oil ($/Bbl)	$ 68.08	$ 75.93	$ 61.52	$ 71.53	$ 54.65	$ 55.72
WTI oil ($/Bbl)	$ 58.81	$ 69.50	$ 55.40	$ 64.76	$ 50.53	$ 53.04
Henry Hub natural gas ($/MMBtu)	$ 3.64	$ 2.90	$ 2.93	$ 3.09	$ 3.00	$ 3.66

CURRENT HEDGING SUMMARY

As of February 28, 2019, our positions were as follows:

	Q1 2019	**Q2 2019**	**Q3 2019**	**Q4 2019**
Net Purchased/Sold Oil Put Options (ICE Brent):				
Hedged volume (MBbls)	484	1,365	368	368
Weighted-average price ($/Bbl)	$ 61.16	$ 61.00	$ 50.00	$ 50.00
Fixed Price Oil Swaps (ICE Brent):				
Hedged volume (MBbls)	1,080	$ 637	644	644
Weighted-average price ($/Bbl)	$ 75.76	$ 76.27	$ 76.27	$ 76.27
Oil basis differential positions (ICE Brent-NYMEX WTI basis swaps):				
Hedged volume (MBbls)	45	46	46	46
Weighted-average price ($/Bbl)	$ (1.29)	$ (1.29)	$ (1.29)	$ (1.29)
Fixed Price Gas Purchase Swaps (Kern, Delivered):				
Hedged volume (MMBtu)	1,815,000	$ 2,730,000	1,380,000	465,000
Weighted-average price ($/MMBtu)	$ 2.68	$ 2.70	$ 2.65	$ 2.65

OPERATING EXPENSES

	Berry Corp. (Successor)					Berry LLC (Predecessor)
	Quarter Ended December 31, 2018	**Quarter Ended September 30, 2018**	**Quarter Ended December 31, 2017**	**Year Ended December 31, 2018**	**Ten Months Ended December 31, 2017**	**Two Months Ended February 28, 2017**
	($ in thousands except per MBoe amounts)					
Lease operating expenses	$ 51,308	$ 51,649	$ 44,586	$ 188,776	$ 149,599	$ 28,238
Electricity generation expenses	6,764	6,130	4,701	20,619	14,894	3,197
Electricity sales[(a)]	(9,517)	(14,268)	(6,455)	(35,208)	(21,972)	(3,655)
Transportation expenses	2,220	2,318	593	9,860	19,238	6,194
Transportation sales[(a)]	(274)	(183)	—	(774)	—	—
Marketing expenses	716	437	645	2,140	2,320	653
Marketing revenues[(a)]	(534)	(486)	(793)	(2,322)	(2,694)	(633)

Derivative settlements (received) paid for gas purchases[a]	(2,407)	—	—	(2,407)	—	—
Total operating expenses[a]	$ 48,276	$ 45,597	$ 43,277	$ 180,684	$ 161,385	$ 33,994
Lease operating expenses ($/Boe)	$ 19.96	$ 20.50	$ 17.40	$ 19.16	$ 15.84	$ 13.06
Electricity generation expenses ($/Boe)	2.63	2.43	$ 1.83	2.09	1.58	1.48
Electricity sales ($/Boe)	(3.70)	(5.66)	$ (2.52)	(3.57)	(2.33)	(1.69)
Transportation expenses ($/Boe)	0.86	0.92	$ 0.23	1.00	2.04	2.86
Transportation sales ($/Boe)	(0.11)	(0.07)	$ 0.00	(0.08)	—	—
Marketing expenses ($/Boe)	0.28	0.17	$ 0.25	0.22	0.25	0.30
Marketing revenues ($/Boe)	(0.21)	(0.19)	$ (0.31)	(0.24)	(0.29)	(0.29)
Derivative settlements (received) paid for gas purchases ($/Boe)	(0.94)	—	—	(0.24)	—	—
Total operating expenses ($/Boe)	$ 18.77	$ 18.10	$ 16.89	$ 18.33	$ 17.09	$ 15.72
Total MBoe	2,571	2,520	2,563	9,855	9,443	2,162

(a) We report electricity, transportation and marketing sales separately in our financial statements as revenues in accordance with GAAP. However, these revenues are viewed and used internally in calculating operating expenses which is used to track and analyze the economics of development projects and the efficiency of our hydrocarbon recovery. We purchase third-party gas to generate electricity through our cogeneration facilities to be used in our field operations activities and view the added benefit of any excess electricity sold externally as a cost reduction/benefit to generating steam for our thermal recovery operations. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then is sold to third parties. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and have not been significant to-date. Operating expenses also includes the effect of derivative settlements (received or paid) for gas purchases.

PRODUCTION STATISTICS

	Berry Corp. (Successor)					Berry LLC (Predecessor)
	Quarter Ended December 31, 2018	**Quarter Ended September 30, 2018**	**Quarter Ended December 31, 2017**	**Year Ended December 31, 2018**	**Ten Months Ended December 31, 2017**	**Two Months Ended February 28, 2017**
Net Oil, Natural Gas and NGLs Production Per Day[a]:						
Oil (MBbl/d)						
California	21.7	19.5	19.5	19.7	18.0	17.0
Rockies	2.0	2.8	2.6	2.3	2.6	2.5
East Texas	—	—	—	—	—	—
Hugoton basin	—	—	—	—	—	—
Total oil	23.7	22.3	22.1	22.0	20.6	19.5
Natural gas (MMcf/d)						
California	—	—	—	—	—	—
Rockies	19.3	23.2	26.1	22.1	25.0	27.1
East Texas[c]	2.8	4.3	5.1	4.2	5.7	6.4
Hugoton basin	—	—	—	—	18.7	38.2
Total natural gas	22.1	27.4	31.3	26.3	49.4	71.7
NGLs (MBbl/d)						
California	—	—	—	—	—	—
Rockies	0.6	0.5	0.6	0.6	0.5	0.6
East Texas	—	—	—	—	—	—
Hugoton basin	—	—	—	—	1.4	4.5

Total NGLs	0.6	0.5	0.6	0.6	2.0	5.2
Total Production (MBoe/d)[(b)]	28.0	27.4	27.9	27.0	30.9	36.7

(a) Production represents volumes sold during the period.
(b) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2018, the average prices of ICE (Brent) oil and NYMEX (HH) natural gas were $71.53 per Bbl and $3.09 per Mcf, respectively, resulting in an oil-to-gas ratio of over 4 to 1 on an energy equivalent basis.
(c) On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

CAPITAL EXPENDITURES (ACCRUAL BASIS)

	Berry Corp. (Successor)					Berry LLC (Predecessor)
	Quarter Ended December 31, 2018	**Quarter Ended September 30, 2018**	**Quarter Ended December 31, 2017**	**Year Ended December 31, 2018**	**Ten Months Ended December 31, 2017**	**Two Months Ended February 28, 2017**
	(in thousands)					
Capital expenditures (accrual basis)	53,326	40,243	17,010	147,831	67,963	5,406

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

Adjusted Net Income (Loss) and Adjusted EBITDA are not measures of net income (loss), Levered Free Cash Flow is not a measure of cash flow, and Adjusted General and Administrative Expenses is not a measure of general and administrative expenses, in all cases, as determined by GAAP. Adjusted Net Income (Loss), Adjusted EBITDA, Levered Free Cash Flow and Adjusted General and Administrative Expenses are supplemental non-GAAP financial measures used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted Net Income (Loss) as net income (loss) adjusted for derivative gains or losses net of cash received or paid for scheduled derivative settlements, other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items and the income tax expense or benefit of these adjustments using our effective tax rate. We define Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, and amortization; derivative gains or losses net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense; and other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items. We define Levered Free Cash Flow as Adjusted EBITDA less capital expenditures, interest expense and dividends. We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for non-recurring restructuring and other costs and non-cash stock compensation expense.

Adjusted Net Income (Loss) excludes the impact of unusual, out-of-period and infrequent items affecting earnings that vary widely and unpredictably, including non-cash items such as derivative gains and losses. This measure is used by management when comparing results period over period. Adjusted EBITDA is the primary financial measurement that our management uses to analyze and monitor the operating performance of our business. Our management believes Adjusted EBITDA provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry and the investment community. The measure also allows our management to more effectively evaluate our operating performance and compare the results between periods without regard to our financing methods or capital structure. Levered Free Cash Flow is used by management as a primary metric to plan capital allocation for maintenance and internal growth opportunities, as well as hedging needs. It also serves as a measure for assessing our financial performance and our ability to generate excess cash from operations to service debt and pay dividends. Management believes Adjusted General and Administrative Expenses is useful because it allows us to more effectively compare our performance from period to period. We exclude the items listed above from general and administrative expenses in arriving at Adjusted General and Administrative Expenses because these amounts can vary widely and unpredictably in nature, timing, amount and frequency and stock compensation expense is non-cash in nature.

While Adjusted Net Income (Loss), Adjusted EBITDA, Adjusted EBITDA Unhedged, Levered Free Cash Flow, Levered Free Cash Flow Unhedged and Adjusted General and Administrative Expenses are non-GAAP measures, the amounts included in the calculations of Adjusted Net Income (Loss), Adjusted EBITDA, Adjusted EBITDA Unhedged, Levered Free Cash Flow, Levered Free Cash Flow Unhedged and Adjusted General and Administrative Expenses were computed in accordance with GAAP. These measures are provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP and Adjusted General and Administrative Expenses should not be considered as an alternative to, or more meaningful than, general and administrative expenses as determined in accordance with GAAP. Our computations of Adjusted Net Income (Loss), Adjusted EBITDA, Adjusted EBITDA Unhedged, Levered Free Cash Flow, Levered Free Cash Flow Unhedged and Adjusted General and Administrative Expenses may not be comparable to other similarly titled measures used by other companies. Adjusted Net Income (Loss), Adjusted EBITDA, Adjusted EBITDA Unhedged, Levered Free Cash Flow, Levered Free Cash Flow Unhedged and Adjusted General and Administrative Expenses should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Management believes that PV-10 provides useful information to investors because it is widely used by analysts and investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, management believes the use of a pre-tax measure is valuable for evaluating the Company. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

Finding and Development cost ("F&D") and reserves replacement ratio are non-GAAP measures that we believe are widely used in our industry, as well as by analysts and investors, to measure and evaluate the cost of replacing annual production and adding proved reserves. F&D Cost – All-In is calculated by dividing total costs incurred for the year as defined by GAAP by the sum of proved reserve extensions and discoveries, revisions of previous estimates, improved recovery and purchases of minerals in place for the year. F&D Cost – Program is calculated by dividing total costs incurred for the year as defined by GAAP by extensions and discoveries and improved recovery for the year. Reserves replacement ratio is calculated by dividing the sum of proved reserve extensions and discoveries, revisions of previous estimates, improved recovery and purchases and sales of minerals in place for the year by current year production. There is no guarantee that historical sources of reserves additions will continue performing as many factors fully or partially outside of management's control, including commodity prices, availability of capital and the underlying geology, affect reserves additions. Management uses this measure to gauge results of its capital allocation. The measure is limited in that reserves may be added and produced based on costs incurred in separate periods and other oil and gas producers may use different measures affecting comparability.

ADJUSTED NET INCOME (LOSS)

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

	Berry Corp. (Successor)					Berry LLC (Predecessor)
	Quarter Ended December 31, 2018	Quarter Ended September 30, 2018	Quarter Ended December 31, 2017	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
	($ thousands, except per share amounts)					
Net income (loss)	$ 131,768	$ 36,985	$ (34,880)	$ 147,102	$ (21,068)	$ (502,964)
Add (Subtract):						
(Gains) losses on oil and natural gas derivatives	(131,637)	17,115	72,542	(1,735)	66,900	(12,886)
Net cash received (paid) for scheduled derivative settlements	8,679	(1,052)	(6,834)	(38,482)	3,068	534
(Gains) losses on sale of assets and other, net	(3,269)	400	(2,243)	(2,747)	(22,930)	(183)
Non-recurring restructuring and other costs	1,414	1,598	2,904	6,773	30,325	—
Reorganization items, net	(1,498)	(13,781)	730	(24,690)	1,732	507,720
Total additions, net	(126,311)	4,280	67,099	(60,881)	79,095	495,185
Income tax (expense) benefit of adjustments at effective tax rate[(a)]	29,352	(736)	(10,384)	13,780	(22,147)	—
Adjusted net income (loss)	$ 34,809	$ 40,529	$ 21,835	$ 100,001	$ 35,880	$ (7,779)
Basic EPS on adjusted income	$ 0.41	$ 0.57	$ 0.57	$ 1.73	$ 0.93	n/a
Diluted EPS on adjusted net income	$ 0.41	$ 0.48	$ 0.29	$ 1.26	$ 0.48	n/a
Weighted average shares outstanding - basic	84,367	70,940	38,644	57,743	38,644	n/a
Weighted average shares outstanding - diluted .	84,592	84,487	74,703	79,633	74,569	n/a

(a) For the ten months ended December 31, 2017, our effective tax rate was (15%) due to a net loss and valuation allowances. For purposes of this calculation, we used the statutory rate for this period, which was 28%.

ADJUSTED EBITDA AND ADJUSTED EBITDA UNHEDGED

The following tables present a reconciliation of the GAAP financial measures of net income (loss) and net cash provided (used) by operating activities to the non-GAAP financial measures of Adjusted EBITDA and Adjusted EBITDA Unhedged.

	Berry Corp. (Successor)					Berry LLC (Predecessor)
	Quarter Ended December 31, 2018	Quarter Ended September 30, 2018	Quarter Ended December 31, 2017	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
	($ thousands)					
Net income (loss)	$ 131,768	$ 36,985	$ (34,880)	$ 147,102	$ (21,068)	$ (502,964)
Add (Subtract):						
Interest expense	8,820	9,877	5,972	35,648	18,454	8,245
Income tax expense (benefit)	39,890	7,683	(6,386)	43,035	2,803	230
Depreciation, depletion, amortization and accretion	24,253	21,729	20,086	86,271	68,478	28,149
Derivative (gains) losses	(131,637)	17,115	72,542	(1,735)	66,900	(12,886)
Net cash received (paid) for scheduled derivative settlements	8,679	(1,052)	(6,834)	(38,482)	3,068	534
(Gains) losses on sale of assets and other	(3,269)	400	(2,243)	(2,747)	(22,930)	(183)
Stock compensation expense	3,249	1,182	949	6,750	1,851	—
Non-recurring restructuring and other costs	1,414	1,598	2,904	6,773	30,325	—
Reorganization items, net	(1,498)	(13,781)	730	(24,690)	1,732	507,720
Adjusted EBITDA	$ 81,669	$ 81,736	$ 52,840	$ 257,924	$ 149,613	$ 28,845
Net cash (received) paid for scheduled derivative settlements	(8,679)	1,052	6,834	38,482	(3,068)	(534)
Adjusted EBITDA unhedged	$ 72,990	$ 82,788	$ 59,674	$ 296,406	$ 146,545	$ 28,311
Net cash provided (used) by operating activities	$ 95,767	$ 56,880	$ 39,086	$ 103,100	$ 107,399	$ 22,431
Add (Subtract):						
Cash interest payments	562	15,902	4,690	19,761	14,276	8,057
Cash income tax (receipts) payments	(1,901)	—	—	(1,901)	1,994	—
Cash reorganization item (receipts) payments	(174)	(345)	794	832	1,732	11,838
Non-recurring restructuring and other costs	1,414	1,598	2,904	6,773	30,325	—
Derivative early termination payment	—	—	—	126,949	—	—
Other changes in operating assets and liabilities	(13,998)	7,701	5,365	2,410	(6,113)	(13,323)
Other, net	—	—	—	—	—	(158)
Adjusted EBITDA	$ 81,669	$ 81,736	$ 52,840	$ 257,924	$ 149,613	$ 28,845
Net cash (received) paid for scheduled derivative settlements	(8,679)	1,052	6,834	38,482	(3,068)	(534)
Adjusted EBITDA unhedged	$ 72,990	$ 82,788	$ 59,674	$ 296,406	$ 146,545	$ 28,311

LEVERED FREE CASH FLOW

The following table presents a reconciliation of Adjusted EBITDA to the non–GAAP measures of Levered free cash flow. The reconciliation of Adjusted EBITDA is presented above.

	Berry Corp. (Successor)					Berry LLC (Predecessor)
	Quarter Ended December 31, 2018	Quarter Ended September 30, 2018	Quarter Ended December 31, 2017	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
	($ thousands)					
Adjusted EBITDA	$ 81,669	$ 81,736	$ 52,840	$ 257,924	$ 149,613	$ 28,845
Subtract:						
Capital expenditures - accrual basis	(53,326)	(40,243)	(17,010)	(147,831)	(67,963)	(5,406)
Interest expense	(8,820)	(9,877)	(5,972)	(35,648)	(18,454)	(8,245)
Dividends	(9,992)	(7,365)	5,567	(28,658)	(18,248)	—
Levered free cash flow	$ 9,531	$ 24,251	$ 35,425	$ 45,787	$ 44,948	$ 15,194
Net cash (received) paid for scheduled derivative settlements	(8,679)	1,052	6,834	38,482	(3,068)	(534)
Levered free cash flow unhedged	$ 852	$ 25,303	$ 42,259	$ 84,269	$ 41,880	$ 14,660

ADJUSTED GENERAL AND ADMINISTRATIVE EXPENSES

The following table presents a reconciliation of the GAAP financial measure of general and administrative expenses to the non-GAAP financial measures of Adjusted general and administrative expenses.

	Berry Corp. (Successor)					Berry LLC (Predecessor)
	Quarter Ended December 31, 2018	Quarter Ended September 30, 2018	Quarter Ended December 31, 2017	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
	($ in thousands except per MBoe amounts)					
General and administrative expenses	$ 16,130	$ 13,429	$ 12,480	$ 54,026	$ 56,009	$ 7,964
Subtract:						
Non-recurring restructuring and other costs	(1,414)	(1,598)	(2,904)	(6,773)	(30,325)	—
Non-cash stock compensation expense	(3,183)	(1,125)	(917)	(6,585)	(1,819)	—
Adjusted general and administrative expenses	$ 11,533	$ 10,706	$ 8,659	$ 40,668	$ 23,865	$ 7,964
General and administrative expenses ($/Boe)	$ 6.27	$ 5.33	$ 4.87	$ 5.48	$ 5.93	$ 3.68
Subtract:						
Non-recurring restructuring and other costs ($/Boe)	(0.55)	(0.63)	(1.13)	(0.69)	(3.21)	—
Non-cash stock compensation expense ($/Boe)	(1.24)	(0.45)	(0.36)	(0.67)	(0.19)	—
Adjusted general and administrative expenses ($/Boe)	$ 4.49	$ 4.25	$ 3.38	$ 4.13	$ 2.53	$ 3.68
Total MBoe	2,571	2,520	2,563	9,855	9,443	2,162

RESERVES AND PV-10

The following table summarizes our estimated proved reserves and related PV-10 as of December 31, 2018.

	December 31, 2018		
	California (San Joaquin and Ventura basins)	Rockies (Uinta and Piceance basins)	Total
Proved developed reserves:			
Oil (MMBbl)	66	7	73
Natural Gas (Bcf)	—	76	76
NGLs (MMBbl)	—	1	1
Total (MMBoe)(a)	66	21	87
Proved undeveloped reserves:			
Oil (MMBbl)	40	2	42
Natural Gas (Bcf)	—	85	85
NGLs (MMBbl)	—	—	—
Total (MMBoe)(a)	40	16	56
Total proved reserves:			
Oil (MMBbl)	106	9	115
Natural Gas (Bcf)	—	161	161
NGLs (MMBbl)	—	1	1
Total (MMBoe)(a)	106	37	143
PV-10 ($MM)(b)	$ 2,027	$ 125	$ 2,152

(a) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2018, the average prices of ICE (Brent) oil and NYMEX (Henry Hub) natural gas were $71.53 per Bbl and $3.09 per Mcf, respectively, resulting in an oil-to-gas ratio of over 4 to 1 on an energy equivalent basis.

(b) For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see “Non-GAAP Financial Measures and Reconciliations—PV-10.” PV-10 does not give effect to derivatives transactions.

The following table provides a reconciliation of PV-10 of our proved reserves to the standardized measure of discounted future net cash flows at December 31, 2018:

	At December 31, 2018 (in millions)
California PV-10	$ 2,027
Rockies PV-10	125
Total Company PV-10	2,152
Less: present value of future income taxes discounted at 10%	(390)
Standardized measure of discounted future net cash flows	$ 1,762

RESERVES REPLACEMENT AND COSTS

The total changes to our proved reserves in 2018, as well as the related costs incurred, were as follows:

	Total Company	California
	(in MMBoe, except ratio and cost amounts)	
Extensions and discoveries (B)	22.4	19.3
Revisions of previous estimates	(10.1)	(0.4)
Purchases of minerals	0.9	0.9
Organic changes (C)	13.2	19.8
Sales of minerals	(2.0)	—

Total reserves changes		11.2	19.8
Production		9.9	7.2
Reserve replacement ratio		114 %	275 %
Costs incurred (development costs)(A) ($ millions)	$	143.0	
Finding & Development costs per Boe			
All-In (A)/(C)	$	10.83	
Program (A)/(B)	$	6.38	

(a) All costs incurred in 2018 were development costs.

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