Berry Petroleum Company, LLC Logo

Berry Petroleum Reports Third Quarter 2018 Results, Announces Quarterly Dividend

November 8, 2018

BAKERSFIELD, Calif., Nov. 07, 2018 (GLOBE NEWSWIRE) -- Berry Petroleum Corporation (NASDAQ: BRY) ("Berry" or the "Company") today reported a net loss attributable to common stockholders of $50 million and adjusted net income of $41 million for the third quarter of 2018. Earnings per share for the third quarter was a net loss of $0.66 per diluted share and adjusted net income of $0.47 per diluted share. In addition, the Board approved a regular $0.12 per share dividend for the fourth quarter of 2018.

Highlights for the Quarter

- Adjusted EBITDA of $82 million and Unhedged Adjusted EBITDA of $83 million
- Adjusted net income for the third quarter of $41 million or $0.47 per diluted share
- September 2018 monthly production of 28,200 Boe/d, a more than 5% increase over second quarter 2018
- California oil price realizations of 91% of Brent pricing or $69.13/Bbl before hedging
- Capital Expenditures of $40 million with approximately 90% directed to California oil development
- Drilled 68 wells in the quarter, on track for over 200 wells drilled in 2018

Trem Smith, Berry president and chief executive officer stated, "Our solid third quarter results are a direct reflection of the new culture that now resides at Berry. First, we are executing our plan with excellence which means we are demonstrating the flexibility and adaptability of the plan. This is a key outcome and has assisted us in staying on plan despite some timing issues in our permitting process. In addition, the results of the entrepreneurship and innovation that is now in Berry are having an impact. As an example, we have successfully drilled a total of 11 new horizontal wells in our North Midway Sunset location and had seven producing at quarter end. These seven are producing at approximately 2,000 barrels of oil per day gross and they are producing without the need for steam to heat the reservoir. These exceptional results have opened up a new trend in an area considered to be mature by the industry. This program was not in our original 2018 development plan but was identified as a new opportunity by our development team.

These development projects are exactly the type of opportunity that brought me to Berry and I'm more excited about our ability to maximize our potential than ever. The inventory of new, high value development opportunities in what are thought to be mature fields is growing and our focus on operational excellence and safety coupled with our willingness to return meaningful capital to our shareholders is why I see a company that will prosper throughout the cycle well into the future."

Quarterly Results

Adjusted net income was $41 million for the third quarter compared to $15 million for the second quarter of 2018. The improved adjusted net income in the third quarter of 2018 compared to the second quarter reflected higher production, lower scheduled hedge payments, and flat crude prices partially offset by higher operating expenses, general and administrative expenses and interest expense.

For the third quarter, Berry reported Adjusted EBITDA of $82 million compared to $50 million for the second quarter. Adjusted EBITDA, on an unhedged basis, was $83 million in the third quarter compared to $78 million in the second quarter.

For the third quarter California oil prices before hedges averaged $69.13/Bbl which were 1% higher than the $68.73/Bbl realized in the second quarter. Realized oil prices for the Company before hedges were $67.67/Bbl and $67.93/Bbl in the third and second quarters, respectively.

Production, adjusting for the timing effects of Utah sales, for the third quarter of 2018 averaged 27,100 barrels of oil equivalent per day (Boe/d) up from 26,800 Boe/d in the second quarter. Production continues to increase as a result of our capital program as the Company averaged 28,200 Boe/d for the month of September 2018, an over 5% increase compared to last quarter.

Oil sales volumes averaged 22,300 barrels per day in the third quarter, natural gas averaged 27,400 Mcf per day and NGLs averaged 500 barrels per day. California provided 19,500 Boe/d in the third quarter, Utah provided 5,100 Boe/d and Colorado and Texas collectively provided 2,800 Boe/d. Utah oil sales benefited in the current quarter as previously discussed refinery constraints lessened in the Uinta Basin.

For the third quarter, Operating Expenses (OpEx) totaled $46 million or $18.10/Boe compared to $41 million or $16.89/Boe in the second quarter. OpEx consists of lease operating expenses (LOE), as well as expenses and third-party revenues from electricity generation, transportation and marketing activities and excludes taxes other than income taxes. The OpEx increase was primarily driven by an increase in LOE which were up primarily due to higher fuel and steam costs as well as maintenance costs, largely offset by increased electricity sales. Berry partially mitigates its exposure to natural gas prices by selling a portion of electricity from our cogeneration operations as the electricity sales prices are closely tied to the price of gas.

General and administrative expenses were $13.4 million for the third quarter compared to $12.5 million for the second quarter. Adjusted general and administrative expenses were $10.7 million or $4.25/Boe for the third quarter compared to $9.5 million or $3.95/Boe for the second quarter. The increases in both general and administrative expenses and adjusted general and administrative expenses were primarily due to increased costs associated with supporting the Company's growth and public company status.

Taxes, other than income taxes were $8.3 million, or $3.30/Boe for the third quarter, compared to $8.7 million or $3.62/Boe in the second quarter.

Capital expenditures totaled $40 million for the third quarter compared to $39 million for the second quarter. The Company ran a three-rig drilling program in California during the third quarter, drilling 68 wells.

As of September 30, 2018 our elected commitment was $400 million, we had $7 million in Letters of Credit and $393 million available for borrowing under the RBL Facility. For the third quarter we generated levered free cash flow of $24 million, or $25 million on an unhedged basis. The Company has current liquidity of $415 million and a cash balance of $22 million.

“The GAAP financials were impacted by various transactions, including the conversion of the preferred shares to common and related distribution and the IPO, and we still have some reorganization items and restructuring charges. We are proud of the adjusted results and we are excited to have completed our 2019 budget and to announce the key components of next year's guidance,” stated Cary Baetz, Chief Financial Officer. “Furthermore, our continued focus on paying an attractive dividend supports the commitment of returning capital that we set out to deliver from day one.”

The Company continues to realign its asset portfolio and recently signed a Purchase and Sale Agreement for its East Texas properties which represent approximately 700 Boe/d of the third quarter's volumes and produce 100% gas. The transaction is expected to close in the fourth quarter of 2018, subject to customary closing conditions.

Full-Year 2019 Guidance [(1)]

- Production between 29,000 to 32,000 Boe/d, approximately 86% oil
- OPEX ranging from $17.00 to $18.50 per Boe
- Taxes, other than income taxes, ranging from $4.25 to $4.75 per Boe
- Adjusted G&A ranging from $4.00 to $4.50 per Boe
- CapEx ranging from $230 million to $260 million

[(1)] The 2019 production guidance excludes 700 Boe/d related to the anticipated sale of E. Texas assets

Full-Year 2018 Guidance

- Production between 27,000 to 30,000 Boe/d, approximately 80% oil
- OPEX ranging from $17.00 to $18.75 per Boe
- Taxes, other than income taxes, ranging from $3.25 to $3.50 per Boe
- Adjusted G&A ranging from $3.75 to $4.00 per Boe
- CapEx ranging from $140 million to $160 million

Dividend Announcement

On November 7, 2018 the Board declared a regular dividend for the fourth quarter at a rate of $0.12 per share on the Company’s outstanding common stock. This is the Company's second regular quarterly dividend, and the Company, subject to approval by the Board, intends to pay a similar dividend in future quarters.

The fourth quarter dividend is payable on January 15, 2019 to shareholders of record at the close of business on December 17, 2018.

Earnings Conference Call

The Company will host a conference call November 8, 2018 to discuss these results:

Live Call Date:	Thursday, November 8, 2018
Live Call Time:	11:00 a.m. Eastern Time (8 a.m. Pacific Time)
Live Call Dial-in:	877-491-5169 from the U.S.
	720-405-2254 from international locations
Live Call Passcode:	1998975

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, November 22, 2018
Replay Dial-in:	855-859-2056 from the U.S.
	404-537-3406 from international locations
Replay Passcode:	1998975

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) California-based independent upstream energy company engaged primarily in the development and production of onshore conventional oil reserves located in the western United States. 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,
- expected production and costs,
- reserves, hedging activities,
- capital investments 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 (NGL) 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 or pending 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 meet our proposed drilling schedule and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
- effects of competition;
- our ability to make acquisitions and successfully integrate any acquired businesses; 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

	Quarter Ended		
	September 30, 2018	June 30, 2018	September 30, 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	$ 147,004	$ 137,385	$ 101,763
Electricity sales	14,268	5,971	8,914
Gains (losses) on oil derivatives	(18,994)	(78,143)	(42,443)
Marketing revenues	486	518	811
Other revenues	183	251	865
Total revenues and other	142,947	65,982	69,910
Expenses and other:			
Lease operating expenses	51,649	41,517	46,224
Electricity generation expenses	6,130	3,135	4,580
Transportation expenses	2,318	2,343	5,586
Marketing expenses	437	407	674
General and administrative expenses	13,429	12,482	11,729
Depreciation, depletion, amortization and accretion	21,729	21,859	20,822
Taxes, other than income taxes	8,317	8,715	11,782

(Gains) losses on natural gas derivatives	(1,879)	—	—
(Gains) losses on sale of assets and other, net	400	123	(20,692)
Total expenses and other	102,530	90,581	80,705
Other income (expenses):			
Interest expense	(9,877)	(9,155)	(5,882)
Other, net	347	(239)	1,155
Total other income (expenses)	(9,530)	(9,394)	(4,727)
Reorganization items, net	13,781	456	(408)
Income (loss) before income taxes	44,668	(33,537)	(15,930)
Income tax expense (benefit)	7,683	(5,476)	(6,246)
Net income (loss)	36,985	(28,061)	(9,684)
Series A preferred stock dividends and conversion to common stock	(86,642)	(5,650)	(5,485)
Net income (loss) attributable to common stockholders	$ (49,657)	$ (33,711)	$ (15,169)
Net income (loss) per share attributable to common stockholders			
Basic	$ (0.66)	$ (0.84)	$ (0.38)
Diluted	$ (0.66)	$ (0.84)	$ (0.38)
Weighted-average common shares outstanding - basic[a]	75,211	40,090	40,000
Weighted-average common shares outstanding - diluted[a]	75,211	40,090	40,000
Adjusted net income (loss)	$ 40,529	$ 14,831	$ 7,826
Adjusted EBITDA	$ 81,736	$ 50,018	$ 40,859
Adjusted EBITDA unhedged	$ 82,788	$ 78,279	$ 36,814
Levered free cash flow	$ 24,185	$ (3,319)	$ 18,075
Levered free cash flow unhedged	$ 25,237	$ 24,942	$ 14,030
Adjusted general and administrative expenses	$ 10,706	$ 9,508	$ 7,848
Effective Tax Rate	17 %	16 %	39 %
<u>Cash Flow Data:</u>			
Net cash provided by (used in) operating activities[b]	$ 56,880	$ (77,394)	$ 25,568
Net cash provided by (used in) investing activities	$ (40,028)	$ (22,472)	$ (2,234)
Net cash provided by (used in) financing activities	$ (16,250)	$ 34,538	$ (28,056)

(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.
(b) 2nd Quarter 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 $50 million.

	September 30, 2018	**December 31, 2017**
	($ and shares in thousands)	
Balance Sheet Data:		
Total current assets	$ 102,903	$ 137,524
Total property, plant and equipment, net	$ 1,418,366	$ 1,387,191
Total current liabilities	$ 144,267	$ 182,659
Long-term debt	$ 391,512	$ 379,000
Total equity	$ 889,110	$ 859,310
Issued and Outstanding common stock shares as of[c]	81,365	32,920

(c) Excludes 7,080,000 common stock shares reserved for general unsecured creditors electing to settle claims in exchange for common shares. All claims have yet to be settled, however, management has been and continues negotiating with these creditors which may reduce the impact of dilution by 3 to 4 million shares.

COMMODITY PRICING

Quarter Ended

	September 30, 2018	June 30, 2018	September 30, 2017
Realized Prices			
Oil without hedge ($/Bbl)	$ 67.67	$ 67.93	$ 45.50
Effects of scheduled derivative settlements ($/Bbl)	$ (0.44)	$ (14.71)	$ 2.07
Oil with hedge ($/Bbl)	$ 67.23	$ 53.22	$ 47.57
Natural gas ($/Mcf)	$ 2.55	$ 2.12	$ 2.76
NGLs ($/Bbl)	$ 37.75	$ 24.38	$ 21.74
Index Prices			
Brent oil ($/Bbl)	$ 75.93	$ 74.87	$ 52.21
WTI oil ($/Bbl)	$ 69.50	$ 67.76	$ 48.20
Henry Hub natural gas ($/Mcf)	$ 2.90	$ 2.80	$ 3.00

CURRENT HEDGING SUMMARY

	4th Quarter 2018	Fiscal Year 2019	Fiscal Year 2020
Sold Oil Calls (ICE Brent):			
Hedged volume (MBbls)	124	—	—
Weighted-average price ($/Bbl)	$ 80.00	$ —	$ —
Purchased Oil Put Options (ICE Brent):			
Hedged volume (MBbls)	—	3,385	455
Weighted-average price ($/Bbl)	$ —	$ 65.00	$ 65.00
Fixed Price Oil Swaps (ICE Brent):			
Hedged volume (MBbls)	1,058	2,640	$ —
Weighted-average price ($/Bbl)	$ 74.82	$ 75.40	$ —
Oil basis differential positions:			
ICE Brent-NYMEX WTI basis swaps			
Hedged volume (MBbls)	92	182.5	—
Weighted-average price ($/Bbl)	$ 1.29	$ 1.29	$ —
Fixed Price Gas Swaps (Kern, Delivered):			
Hedged volume (MMBtu)	1,380,000	4,560,000	$ —
Weighted-average price ($/MMBtu)	$ 2.65	$ 2.65	$ —

OPERATING EXPENSES

	Quarter Ended		
	September 30, 2018	June 30, 2018	September 30, 2017
	($ in thousands except per MBoe amounts)		
Lease operating expenses	$ 51,649	$ 41,517	$ 46,224
Electricity generation expenses	6,130	3,135	4,580
Electricity sales[(a)]	(14,268)	(5,971)	(8,914)
Transportation expenses	2,318	2,343	5,586
Transportation sales[(a)]	(183)	(251)	—
Marketing expenses	437	407	674
Marketing revenues[(a)]	(486)	(518)	(811)
Total operating expenses[(a)]	$ 45,597	$ 40,662	$ 47,339
Lease operating expenses ($/MBoe)	$ 20.50	$ 17.24	$ 17.22
Electricity generation expenses ($/MBoe)	2.43	1.30	1.71
Electricity sales ($/MBoe)	(5.66)	(2.48)	(3.32)
Transportation expenses ($/MBoe)	0.92	0.97	2.08
Transportation sales ($/MBoe)	(0.07)	(0.09)	—
Marketing expenses ($/MBoe)	0.17	0.17	0.25

Marketing revenues ($/MBoe)	(0.19)	(0.22)	(0.30)
Total operating expenses ($/MBoe)	$ 18.10	$ 16.89	$ 17.64
Total MBoe	2,520	2,408	2,684

(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, reported in "Other Revenues", relates to water and other liquids that we transport on our systems on behalf of third parties.

PRODUCTION STATISTICS

	Quarter Ended		
	September 30, 2018	**June 30, 2018**	**September 30, 2017**
Net Oil, Natural Gas and NGLs Production Per Day[a]:			
Oil (MBbl/d)			
California	19.5	18.8	18.8
Hugoton basin	—	—	—
Uinta basin	2.8	2.3	2.4
Piceance basin	—	—	—
East Texas	—	—	—
Total oil	22.3	21.1	21.2
Natural gas (MMcf/d)			
California	—	—	—
Hugoton basin	—	—	12.9
Uinta basin	11.2	13.8	10.9
Piceance basin	11.9	9.4	6.7
East Texas	4.1	4.8	6.0
Total natural gas	27.4	28.0	36.5
NGLs (MBbl/d)			
California	—	—	—
Hugoton basin	—	—	1.1
Uinta basin	0.5	0.7	0.8
Piceance basin	—	—	—
East Texas	—	—	—
Total NGLs	0.5	0.7	1.9
Total Production (MBoe/d)[b]	27.4	26.5	29.2

(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, 2017, the average prices of ICE (Brent) oil and NYMEX Henry Hub natural gas were $54.82 per Bbl and $3.11 per Mcf, respectively, resulting in an oil-to-gas ratio of over 17 to 1.

CAPITAL EXPENDITURES ACCRUAL BASIS

(in thousands)	**Quarter Ended September 30 2018**	**Quarter Ended June 30 2018**	**Quarter Ended September 30 2017**
Capital expenditures- accrual basis	$ 40,243	$ 38,531	$ 16,902

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) attributable to common stockholders 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 and reorganization costs and the income tax expense or benefit of these adjustments using the Company's effective tax rate. We define Adjusted EBITDA as earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion; derivative gains or losses net of cash received or paid for scheduled derivative settlements; asset impairments, stock compensation expense, and other unusual, out-of-period and infrequent items, including restructuring and reorganization costs. 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 earning that vary widely and unpredictably, including non-cash items such as derivatives 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 reflects our financial flexibility; and we use it to plan our internal growth capital expenditures. Levered Free Cash Flow is our primary metric used in planning capital allocation for maintenance and internal growth opportunities as well as hedging needs and serves as a measure for assessing our financial performance and measuring our ability to generate excess cash from our operations after servicing indebtedness. 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.

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).

($ thousands, except per share amounts)	**Quarter Ended September 30 2018**	**Quarter Ended June 30 2018**	**Quarter Ended September 30 2017**
Net income (loss)	$ 36,985	$ (28,061)	$ (9,684)
Add (Subtract):			—
(Gains) losses on oil and natural gas derivatives	17,115	78,143	42,443
Net cash received (paid) for scheduled derivative settlements	(1,052)	(28,261)	4,045
Gains (losses) on sale of assets and other, net	400	123	(20,692)
Non-recurring restructuring and other costs	1,598	1,714	2,979
Reorganization items, net	(13,781)	(456)	408
Total additions, net	4,280	51,263	29,183
Income tax (expense) benefit of adjustments at effective tax rate	(736)	(8,371)	(11,673)
Adjusted net income (loss)	$ 40,529	$ 14,831	$ 7,826
Basic EPS on adjusted income	$ 0.54	$ 0.37	$ 0.78
Diluted EPS on adjusted net income	$ 0.47	$ 0.19	$ 0.41

Weighted average shares outstanding - basic	75,211	40,090	40,000
Weighted average shares outstanding - diluted	85,667	77,845	76,198

ADJUSTED EBITDA AND ADJUSTED EBITDA UNHEDGED

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

	Quarter Ended		
	September 30, 2018	June 30, 2018	September 30, 2017
		($ thousands)	
Net income (loss)	$ 36,985	$ (28,061)	$ (9,684)
Add (Subtract):			
Interest expense	9,877	9,155	5,882
Income tax expense (benefit)	7,683	(5,476)	(6,246)
Depreciation, depletion, amortization and accretion	21,729	21,859	20,822
Derivative (gain) loss	17,115	78,143	42,443
Net cash received (paid) for scheduled derivative settlements	(1,052)	(28,261)	4,045
(Gain) loss on sale of assets and other	400	123	(20,692)
Stock compensation expense	1,182	1,278	902
Non-recurring restructuring and other costs	1,598	1,714	2,979
Reorganization items, net	(13,781)	(456)	408
Adjusted EBITDA	$ 81,736	$ 50,018	$ 40,859
Net cash (received) paid for scheduled derivative settlements	1,052	28,261	(4,045)
Adjusted EBITDA unhedged	$ 82,788	$ 78,279	$ 36,814
Net cash provided (used) by operating activities	56,880	(77,394)	25,568
Add (Subtract):			
Cash interest payments	15,902	644	4,726
Cash income tax payments	—	—	826
Cash reorganization item (receipts) payments	(345)	1,047	417
Non-recurring restructuring and other costs	1,598	1,714	2,979
Derivative early termination payment	—	126,949	—
Other changes in operating assets and liabilities	7,701	(2,942)	6,343
Other, net	—	—	—
Adjusted EBITDA	$ 81,736	$ 50,018	$ 40,859
Net cash (received) paid for scheduled derivative settlements	1,052	28,261	(4,045)
Adjusted EBITDA unhedged	$ 82,788	$ 78,279	$ 36,814

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.

	Quarter Ended		
	September 30, 2018	June 30, 2018	September 30, 2017
		($ thousands)	
Adjusted EBITDA	$ 81,736	$ 50,018	$ 40,859
Subtract:			
Capital expenditures - accrual basis	(40,243)	(38,531)	(16,902)
Interest expense	(9,877)	(9,155)	(5,882)
Dividends	(7,431)	(5,651)	—
Levered free cash flow	$ 24,185	$ (3,319)	$ 18,075

Net cash (received) paid for scheduled derivative settlements	1,052	28,261	(4,045)
Levered free cash flow unhedged	$ 25,237	$ 24,942	$ 14,030

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.

	Quarter Ended		
	September 30, 2018	**June 30, 2018**	**September 30, 2017**
	($ in thousands except per MBoe amounts)		
General and administrative expenses	$ 13,429	$ 12,482	$ 11,729
Subtract:			
Non-recurring restructuring and other costs	(1,598)	(1,714)	(2,979)
Non-cash stock compensation expense	(1,125)	(1,260)	(902)
Adjusted general and administrative expenses	$ 10,706	$ 9,508	$ 7,848
General and administrative expenses ($/MBoe)	$ 5.33	$ 5.19	$ 4.37
Subtract:			
Non-recurring restructuring and other costs ($/MBoe)	(0.63)	(0.71)	(1.11)
Non-cash stock compensation expense ($/MBoe)	(0.45)	(0.52)	(0.34)
Adjusted general and administrative expenses ($/MBoe)	$ 4.25	$ 3.95	$ 2.92
Total MBoe	2,520	2,407	2,684

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