Berry Corporation (bry) Reports Fourth Quarter and Full-Year 2020 Results; Reinstates a Quarterly Dividend

February 23, 2021

DALLAS, Feb. 23, 2021 (GLOBE NEWSWIRE) -- Berry Corporation (bry) (NASDAQ: BRY) ("Berry" or the "Company") today reported fourth quarter and full-year 2020 results. For the full year Berry's net loss was $263 million, or $3.29 per diluted share, and Adjusted Net Income(1) was $45 million, or $0.56 per diluted share. For the fourth quarter the net loss was $64 million, or $0.80 per diluted share, and Adjusted Net Income(1) was $9 million, or $0.11 per diluted share. In addition, the Company's Board of Directors approved a first quarter dividend of $0.04 per share.

Highlights for the Quarter

- Generated $33 million in Levered Free Cash Flow(1)
- Restarted development program with two rigs part time, drilling 22 wells, all California oil
- Adjusted EBITDA(1) of $54 million
- 88% oil production mix
- Capital expenditures of $12 million with approximately 96% directed to California development

Highlights for the Full Year

- Generated $131 million in Levered Free Cash Flow(1)
- Ended year with cash balance of $80 million
- Adjusted EBITDA(1) of $244 million
- Reduced 2020 OpEx by $1.81/Boe
- Increased California oil production more than 1% from 2019 volumes
- Oil production of 25,000 Boe/d comprising 88% of total production
- Capital expenditures of $69 million, approximately 96% directed to California assets

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(1) Please see "Non-GAAP Financial Measures and Reconciliations" later in this press release for a reconciliation and more information on these Non-GAAP measures.

"One of Berry's core financial tenets has always been to live out of Levered Free Cash Flow while protecting our base production. Even in the midst of an unprecedented year, we successfully delivered our plan. We adeptly improved our hedge position before prices plummeted, lowered our costs, and maximized our cash position to weather the volatile environment that was 2020. We committed to all stakeholders that we would enter 2021 in a strong position poised for growth and we are," said Trem Smith, Berry board chair and chief executive officer. "We started 2021 in a strong liquidity position by continuing our cash build and currently have more than $100 million. For 2021, we will utilize our proven financial formula of operating within our Levered Free Cash Flow and returning capital to our shareholders. We are pleased to announce the return of a quarterly dividend justified by the improving price environment, our growing confidence in the business fundamentals for oil and our strong liquidity position. Our cash position and improving oil prices, allow us to put capital to work protecting and growing our California production. We plan to hold year-over-year company-wide production flat in 2021 and anticipate a strong fourth quarter exit rate. In addition, we are laser focused on increasing our scale. Our growth strategy continues to be directed toward conventional, low corporate decline assets with strong visibility to cash flow."

Fourth Quarter 2020 Results

Adjusted EBITDA(1) on a hedged basis, was $54 million in the fourth quarter 2020, compared to $62 million in the third quarter 2020, reflecting lower volumes, as well as lower electricity sales due to seasonal effects and higher workover activity driving higher Operating Expenses (OpEx).

Average daily production in the fourth quarter 2020 of 26,600 Boe/d was 4% lower than the third quarter volumes of 27,600 Boe/d due mainly to natural decline resulting from pausing drilling activity for the majority of the year, with drilling restarting during the fourth quarter. Company-wide oil production declined 3% sequentially and California oil production, which is 80% of total production, was 21,200 MBoe/d for the fourth quarter.

The Company-wide hedged realized oil price for the fourth quarter 2020 was $56.41/Bbl, essentially flat from the third quarter. The financial hedges for oil sales for the fourth quarter 2020 added $15.03/Bbl to the realized price, highlighting the effectiveness of the Company's oil hedge positions in 2020. Company-wide realized oil prices before hedges of $41.38/Bbl was 4% higher in the fourth quarter 2020 compared to the third quarter.

California's unhedged realized oil price in the fourth quarter increased 4% or $1.72 per Bbl to $41.74, which was 92% of Brent and unchanged from the previous quarter. Rockies' unhedged realized oil price declined 2% to $37.56 per Bbl but the Company-wide average price increased 15% as the natural gas price increased 43% to $2.78 per Mcf. The total Company average oil and gas price increased 5% to $38.28 per Boe in the fourth quarter 2020 from $36.35 in the third quarter.

Levered Free Cash Flow(1) for the fourth quarter 2020 was $33 million, after $12 million of capital expenditures and $8 million of interest.

OpEx increased to $19.06/Boe for the fourth quarter 2020, compared to $16.97/Boe in the third quarter. This $4 million increase in OpEx was primarily due to the seasonal effect of lower electricity capacity revenues, as well as the workover and recompletion campaign which began during the fourth quarter, higher natural gas fuel prices, as well as general facility and well maintenance.

General and administrative expenses increased by $1 million, or 6%, to approximately $20 million for the fourth quarter 2020, compared to the third quarter of 2020. Adjusted General and Administrative Expenses[(1)], which excludes non-cash stock compensation costs and nonrecurring costs, were $15 million and $14 million for the fourth and third quarter of 2020, respectively. The higher fourth quarter 2020 expenses reflect increased employee compensation accruals.

Taxes, other than income taxes were $4.43 per Boe in the fourth quarter compared to $3.91 in the third quarter. The increase was largely due to annual property tax assessments in the quarter.

Capital expenditures, which were focused on development activities in California, increased to $12 million for the fourth quarter compared to $4 million for the third quarter. This was due to resuming California drilling activity after more than six months of not drilling because of low prices and an oversupply in the market. These amounts exclude capitalized overhead and interest costs of $2 million for the fourth quarter and expenditures for asset retirement obligation of $4 million.

Full-Year 2020 Results

Adjusted EBITDA[(1)] (hedged) was $244 million for 2020, a decrease of $58 million compared to 2019 primarily due to lower commodity prices and, to a much lesser degree, lower volumes due to the pause of drilling from April to October related to pricing. Offsetting a portion of the price impact was a $22 million reduction in OpEx.

Year-over-year California production increased over 1% to 22,900 Bbl/d, while overall Company production decreased 2% to 28,500 Boe/d in 2020 due to the natural decline of our Rockies properties in the absence of development activity.

California's unhedged realized oil price was $40.01 per Bbl in 2020 and $60.51 in 2019. Rockies' unhedged realized oil price declined to $34.69 per Bbl from $45.78 in 2019. Total Company average oil and gas price decreased $17.10 per Boe from 2019 to $36.29 in 2020. Oil hedge settlements increased to $16.51 per Bbl ($152 million) in 2020 from $4.68 per Bbl in the previous year.

OpEx on a hedged basis decreased $1.81 per Boe, or $22 million from 2019 to $18.51 in 2020. As a result of cost saving and efficiency measures implemented in 2020, Non-Energy OpEx decreased $15 million, or $1.17 per Boe, when compared to the prior year. Energy OpEx decreased $7 million or $0.63 per Boe.

General and administrative expenses increased by $15 million, or 24%, to approximately $78 million for the year ended December 31, 2020, compared to the prior year. Adjusted General and Administrative Expenses[(1)], which excludes non-cash stock compensation costs and nonrecurring costs, were $57 million and $51 million in 2020 and 2019, respectively. The year-over-year increase is due to higher employee compensation and increased activities necessary for our participation in the regulatory and legislative process primarily in California.

Taxes, other than income taxes, decreased to $3.41/Boe in 2020 from $3.84/Boe in 2019. The decrease was largely due to lower greenhouse gas prices during 2020 including some allowance purchases made at low prices due to a temporary market dislocation in the first quarter of 2020, as well as lower CO_2 emissions. Partially offsetting the greenhouse gas prices were higher property tax rates, as well as higher severance tax rates due to the expiration of certain deductions.

Capital expenditures totaled $69 million for 2020 compared to $209 million for 2019. The decrease was due primarily to the reduction in drilling with 45 wells in 2020 compared to 338 in 2019. These amounts exclude capitalized overhead and interest costs. Additionally, we spent $18 million in 2020 on plugging and abandonment activities. Capital was largely focused on development drilling in California, which accounted for 96% of 2020 development capital.

Proved reserves were 95 MMBoe at December 31, 2020, of which 91% are located in California and where 97% of the PV-10[(1)] value is located. The formulaic SEC oil price used to calculate proved reserves decreased 34% year-over-year, which drove a 26% reduction in our proved reserves, before the effect of current year production. Additionally, the significant drop in commodity prices during the year resulted in a significant decline in the Company's capital program, limiting opportunities to prove-up additional reserves. The Company drilled 87% fewer wells in 2020 than in the prior year. Based on current Brent strip pricing the Company anticipates a material improvement in 2021 proved reserves, should prices remain at those levels.

As of December 31, 2020, the elected commitment under Berry's reserves-based lending credit facility ("RBL Facility") was $200 million with no outstanding borrowings. The Company had $193 million available for borrowing under the RBL Facility which included $7 million of outstanding letters of credit.

"We delivered on the promises we made last spring to bridge to the end of 2021 as the pandemic took its hold on the global economy. At the time, we planned for a two-year down-cycle in our industry. We immediately began to cut costs and leverage our strong hedge position in an effort to preserve cash for 2021. At year-end, we had more than $80 million of cash in the bank and currently we have more than $100 million. For 2021, we plan to deploy $120 to $130 million of capital, which should keep our production relatively flat on an annual basis, with an accelerated rate exiting 2021. Like 2020, we plan to see oil growth in our attractive California basin," stated Cary Baetz, executive vice president and chief financial officer. "Notably, our reserve calculations were negatively impacted by the severe price correction caused by the Saudi/Russia market dispute earlier in the year and demand erosion due to Covid-19. However, for 2021, we expect a substantial improvement in our calculated reserves as the current strip prices are more than 40% higher than the SEC prices used for the 2020 reserve calculation."

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(1) Please see "Non-GAAP Financial Measures and Reconciliations" later in this press release for a reconciliation and more information on these Non-GAAP measures.

Quarterly Dividend

The Company's Board of Directors declared a regular dividend for the first quarter of 2021 at a rate of $0.04 per share on the Company’s outstanding common stock, payable on April 15, 2021 to shareholders of record at the close of business on March 15, 2021. This is the Company’s first regular quarterly dividend since its suspension during the price decline in early 2020 related to the pandemic and commodities markets.

Subject to approval by the Board and depending on a variety of factors, including the Company’s financial condition and results of operations, the Company intends to pay a similar dividend in future quarters.

Full-Year 2021 Guidance

The Company expects to employ up to three drilling rigs in California during 2021. Additionally, the Company anticipates drilling approximately 170 to 200 gross development wells during 2021, almost all of which will be in California for oil production.

Full-Year 2021 Guidance	**Low**		**High**
Average Daily Production (MBoe/d)	27.0		29.0
Oil as % of Production		~89%	
Operating Expenses ($/Boe)	$17.25		$18.55
Taxes, Other than Income Taxes ($/Boe)	$3.75		$4.25
Adjusted General & Administrative (G&A) expenses ($/Boe)	$5.50		$6.25
Capital Expenditures ($ millions)	$120		$130
New Drill Wells	170		200

Earnings Conference Call

Berry will host a conference call February 24, 2021 to discuss these results:

Live Call Date:	Wednesday, February 24, 2021
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:	1256432

A live audio webcast will be available on the “Events” section of Berry’s website at bry.com/category/events.

An audio replay will be available shortly after the broadcast:

Replay Dates:	Through Wednesday, March 10, 2021
Replay Dial-in:	855-859-2056 from the U.S.
	404-537-3406 from international locations
Replay Passcode:	1256432

A replay of the audio webcast will also be archived on the “Reports & Resources” section of Berry’s website at ir.bry.com/reports-resources.

About Berry Corporation (bry)

Berry 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 bry.com.

Forward-Looking Statements

The information in this press release includes 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 plans, activities, events, objectives, goals, strategies, or developments that the Company expects, believes or anticipates will or may occur in the future, such as those regarding financial position; liquidity; cash flows; anticipated financial and operating, results; capital program and development and production plans; operations and business strategy; potential acquisition opportunities; reserves; hedging activities; capital expenditures, return of capital; payment, improvement of future dividends; future repurchases of stock or debt; capital investments, recovery factors and other guidance are forward-looking statements. The forward-looking statements in this press release are based upon various assumptions, many of which are based, in turn, upon further assumptions. Although we believe that these assumptions were reasonable when made, these assumptions are inherently subject to significant uncertainties and contingencies which are difficult or impossible to predict and are beyond our control. Therefore, such forward-looking statements involve significant risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects.

Berry cautions you that these forward-looking statements are subject to all of the risks and uncertainties, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil most of which are difficult to predict and many of which are beyond Berry’s control. These risks include, but are not limited to, commodity price volatility; legislative and regulatory actions that may prevent, delay or otherwise restrict our ability to drill and develop our assets, including regulatory approval and permitting requirements; the impact and duration of the ongoing COVID-19 pandemic on demand and pricing levels; legislative and regulatory initiatives in California or our other areas of operation addressing climate change or other environmental concerns; investment in and development of competing or alternative energy sources; drilling and other operating risks; uncertainties inherent in estimating natural gas and oil reserves and in projecting future rates of production; cash flow and access to capital; the timing and funding of development expenditures; environmental risks; effects of hedging arrangements; potential shut-ins of production due to lack of downstream demand or storage capacity; and the other risks described under the heading “Item 1A. Risk Factors” in the Company’s Annual Report on Form 10-K for the year ended December 31, 2020.

You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, budget, continue, could, effort, 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.

Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake 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. Investors are urged to consider carefully the disclosure in our filings with the Securities and Exchange Commission, available from us at via our website or via the Investor Relations contact below, or from the SEC's website at www.sec.gov.

TABLES FOLLOWING

The financial information and certain other information presented 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 December 31, 2020	Quarter Ended September 30, 2020	Quarter Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
	($ and shares in thousands, except per share amounts)				
Consolidated Statement of Operations Data:					
Revenues and other:					
Oil, natural gas and natural gas liquids sales	$ 93,811	$ 92,239	$ 156,336	$ 378,663	$ 565,596
Electricity sales	6,724	8,744	6,844	25,813	29,397
(Losses) gains on oil and gas sales derivatives	(39,617)	(11,564)	(45,544)	117,781	(37,998)
Marketing revenues	351	330	437	1,426	2,094
Other revenues	97	—	55	150	316
Total revenues and other	61,366	89,749	118,128	523,833	559,405
Expenses and other:					
Lease operating expenses	49,621	45,243	59,529	186,348	216,294
Electricity generation expenses	5,422	4,217	4,785	16,608	19,490
Transportation expenses	1,559	1,768	2,124	6,938	8,059
Marketing expenses	344	326	403	1,380	2,073
General and administrative expenses	20,409	19,173	15,710	77,696	62,643
Depreciation, depletion and amortization	30,434	35,905	30,102	139,180	106,006
Impairment of oil and gas properties	—	—	51,081	289,085	51,081
Taxes, other than income taxes	10,858	9,913	11,962	35,572	40,645
Losses (gains) on natural gas purchase derivatives	3,859	(15,784)	(3,385)	1,035	6,957
Other operating expenses (income)	3,123	1,648	774	5,781	4,588
Total expenses and other	125,629	102,409	173,085	759,623	517,836
Other (expenses) income:					
Interest expense	(8,308)	(8,391)	(7,871)	(34,295)	(34,234)
Other, net	(13)	(3)	—	(28)	80
Total other (expenses) income	(8,321)	(8,394)	(7,871)	(34,323)	(34,154)
Reorganization items, net	—	—	—	—	(426)
(Loss) income before income taxes	(72,584)	(21,054)	(62,828)	(270,113)	6,989
Income tax (benefit) expense	(8,754)	(2,190)	(55,844)	(7,218)	(36,550)
Net (loss) income	$ (63,830)	$ (18,864)	$ (6,984)	$ (262,895)	$ 43,539
Net (loss) earnings per share:					
Basic	$ (0.80)	$ (0.24)	$ (0.09)	$ (3.29)	$ 0.54
Diluted	$ (0.80)	$ (0.24)	$ (0.09)	$ (3.29)	$ 0.53
Weighted-average common shares outstanding - basic	79,922	79,879	80,435	79,802	81,379
Weighted-average common shares outstanding - diluted	79,922	79,879	80,435	79,802	81,951
Adjusted Net Income(1)	$ 8,580	$ 13,452	$ 33,189	$ 44,816	$ 110,228
Weighted-average common shares outstanding - diluted	80,033	80,062	80,788	79,902	81,951
Diluted earnings per share on Adjusted Net Income	$ 0.11	$ 0.17	$ 0.41	$ 0.56	$ 1.35
Adjusted EBITDA(1)	$ 53,682	$ 61,515	$ 86,995	$ 244,430	$ 302,184
Adjusted EBITDA unhedged(1)	$ 18,365	$ 26,039	$ 71,529	$ 102,138	$ 259,987
Levered Free Cash Flow(1)	$ 33,011	$ 49,129	$ 28,298	$ 131,451	$ 20,127

Levered Free Cash Flow Unhedged[1]	$ (2,306)	$ 13,653	$ 12,832	$ (10,841)	$ (22,070)
Adjusted General and Administrative Expenses[1]	$ 14,881	$ 13,888	$ 13,421	$ 57,406	$ 51,226
Effective Tax Rate, including discrete items	12 %	10 %	89 %	3 %	(523) %
Cash Flow Data:					
Net cash provided by operating activities	$ 52,110	$ 57,997	$ 77,562	$ 196,529	$ 241,829
Net cash used in investing activities	$ (19,098)	$ (9,004)	$ (63,739)	$ (93,620)	$ (225,025)
Net cash used in financing activities	$ (75)	$ (1,373)	$ (28,675)	$ (22,352)	$ (85,484)

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(1) See further discussion and reconciliation in "Non-GAAP Financial Measures and Reconciliations".

	December 31, 2020	December 31, 2019
	($ and shares in thousands)	
Balance Sheet Data:		
Total current assets	$ 154,491	$ 100,432
Total property, plant and equipment, net	$ 1,258,084	$ 1,576,267
Total current liabilities	$ 175,306	$ 156,628
Long-term debt	$ 393,480	$ 394,319
Total stockholders' equity	$ 714,036	$ 972,448
Outstanding common stock shares as of	79,929	79,543

SUMMARY BY AREA

The following table shows a summary by area of our selected historical financial information and operating data for the periods indicated.

	California (San Joaquin and Ventura basins)		Utah (Uinta basin)		Colorado (Piceance basin)	
	Year Ended December 31, 2020	Year Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
($ in thousands, unless noted otherwise)						
Oil, natural gas and natural gas liquids sales	$ 335,642	$ 498,325	$ 37,481	$ 59,383	$ 5,537	$ 7,740
Operating (loss) income[1]	$ (7,915)	$ 230,500	$ (126,289)	$ 7,624	$ (357)	$ (48,955)
Depreciation, depletion, and amortization (DD&A)	$ 130,388	$ 93,025	$ 7,058	$ 11,754	$ 324	$ 1,055
Impairment of oil and gas properties	$ 163,879	$ —	$ 125,206	$ —	$ —	$ 51,081
Average daily production (MBoe/d)	22.9	22.6	4.3	5.0	1.3	1.4
Production (oil % of total)	100 %	100 %	50 %	54 %	2 %	2 %
Realized sales prices:						
Oil (per Bbl)	$ 40.01	$ 60.51	$ 34.81	$ 45.72	$ 24.01	$ 52.36
NGLs (per Bbl)	$ —	$ —	$ 12.57	$ 17.08	$ —	$ —
Gas (per Mcf)	$ —	$ —	$ 2.22	$ 2.94	$ 1.87	$ 2.26
Capital expenditures[2]	$ 66,398	$ 189,648	$ 1,247	$ 10,229	$ 206	$ 603
Total proved reserves (MMBoe)	87	122	7	15	1	1

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(1) Operating income (loss) includes oil, natural gas and NGL sales, marketing revenues, other revenues, and scheduled oil derivative settlements, offset by operating expenses (as defined elsewhere), general and administrative expenses, DD&A, impairment of oil and gas properties, and taxes, other than income taxes.

(2) Excludes corporate capital expenditures.

COMMODITY PRICING

	Quarter Ended December 31, 2020	Quarter Ended September 30, 2020	Quarter Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
Realized Prices					

Oil without hedge ($/Bbl)	$ 41.38	$ 39.88	$ 59.28	$ 39.56	$ 58.93
Effects of derivative settlements ($/Bbl)	$ 15.03	$ 16.28	$ 5.70	$ 16.51	$ 4.68
Oil with hedge ($/Bbl)	$ 56.41	$ 56.16	$ 64.98	$ 56.07	$ 63.61
Natural gas ($/Mcf)	$ 2.78	$ 1.95	$ 2.60	$ 2.08	$ 2.66
NGLs ($/Bbl)	$ 16.78	$ 13.25	$ 14.60	$ 12.57	$ 17.02
Index Prices					
Brent oil ($/Bbl)	$ 45.26	$ 43.34	$ 62.42	$ 43.21	$ 64.16
WTI oil ($/Bbl)	$ 42.66	$ 40.87	$ 57.02	$ 39.59	$ 57.03
Kern, Delivered natural gas ($/MMBtu)(1)	$ 3.38	$ 2.84	$ 2.99	$ 2.46	$ 3.14
Henry Hub natural gas ($/MMBtu)(2)	$ 2.52	$ 2.00	$ 2.40	$ 2.03	$ 2.56

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(1) Kern, Delivered Index is the relevant index used for gas purchases in California.

(2) Henry Hub is the relevant index used for gas sales in the Rockies.

CURRENT HEDGING SUMMARY

As of December 31, 2020, our positions were as follows:

	Q1 2021	Q2 2021	Q3 2021	Q4 2021
Fixed Price Oil Swaps (Brent):				
Hedged volume (MBbls)	1,710	1,728	1,042	1,042
Weighted-average price ($/Bbl)	$ 45.82	$ 45.82	$ 46.17	$ 46.17
Fixed Price Gas Purchase Swaps (Kern, Delivered):				
Hedged volume (MMBtu)	4,950,000	4,777,500	4,830,000	2,085,000
Weighted-average price ($/MMBtu)	$ 2.69	$ 2.83	$ 2.83	$ 2.95

As of December 31, 2020 we also had open swap positions that are excluded from the table above where we are both buyer and seller of equal notional volumes of 12,500 MMBtu/d of fixed price gas sales swaps each indexed to Northwest Pipeline Rocky Mountains and CIG, for the period January 1, 2021 through December 31, 2021. These swap positions effectively cancel each other while resulting in a mark-to-market gain of $2.6 million. This gain will be cash settled in 2021 as the positions expire

In February 2021, we added 3,000 Bbls/d of fixed price oil swaps (Brent) at approximately $58 for the period July 2021 through December 31, 2021.

OPERATING EXPENSES

	Quarter Ended December 31, 2020	Quarter Ended September 30, 2020	Quarter Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
	($ in thousands except per Boe amounts)				
Expenses:					
Lease operating expenses	$ 49,621	$ 45,243	$ 59,529	$ 186,348	$ 216,294
Electricity generation expenses	5,422	4,217	4,785	16,608	19,490
Electricity sales	(6,724)	(8,744)	(6,844)	(25,813)	(29,397)
Transportation expenses	1,559	1,768	2,124	6,938	8,059
Transportation sales	(97)	—	(55)	(150)	(316)
Marketing expenses	344	326	403	1,380	2,073
Marketing revenues	(351)	(330)	(437)	(1,426)	(2,094)
Derivative settlements (received) paid for gas purchases(1)	(3,090)	614	(906)	9,298	1,059
Total operating expenses(2)	$ 46,684	$ 43,094	$ 58,599	$ 193,183	$ 215,168
Expenses per Boe:(2)					
Lease operating expenses	$ 20.25	$ 17.83	$ 20.69	$ 17.86	$ 20.42
Electricity generation expenses	2.21	1.66	1.66	1.59	1.84
Electricity sales	(2.74)	(3.45)	(2.38)	(2.47)	(2.77)
Transportation expenses	0.64	0.69	0.74	0.66	0.76
Transportation sales	(0.04)	—	(0.02)	(0.01)	(0.03)
Marketing expenses	0.14	0.13	0.14	0.13	0.20
Marketing revenues	(0.14)	(0.13)	(0.15)	(0.14)	(0.20)
Derivative settlements (received) paid for gas purchases	(1.26)	0.24	(0.31)	0.89	0.10
Total operating expenses(2)	$ 19.06	$ 16.97	$ 20.37	$ 18.51	$ 20.32

Total unhedged operating expenses[1]	$	20.32	$	16.73	$	20.68	$	17.62	$	20.22
Total non-energy operating expenses[3]	$	14.35	$	13.34	$	14.96	$	13.63	$	14.80
Total energy operating expenses[4]	$	4.70	$	3.65	$	5.41	$	4.88	$	5.51
Total MBoe		2,450		2,537		2,877		10,435		10,594

(1) Total unhedged operating expenses equals total operating expenses, excluding the derivative settlements paid (received) for gas purchases.

(2) 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 revenues and 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 include the effect of derivative settlements (received or paid) for gas purchases.

(3) Total non-energy operating expenses equals total operating expenses, excluding fuel, electricity sales and gas purchase derivative settlements (gains) losses.

(4) Total energy operating expenses equals fuel and gas purchase derivative settlements (gains) losses less electricity sales.

PRODUCTION STATISTICS

	Quarter Ended December 31, 2020	Quarter Ended September 30, 2020	Quarter Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
Net Oil, Natural Gas and NGLs Production Per Day[1]:					
Oil (MBbl/d)					
California	21.2	22.2	25.5	22.9	22.6
Utah	2.1	1.9	2.2	2.1	2.7
Colorado	—	—	—	—	—
Total oil	23.3	24.1	27.7	25.0	25.3
Natural gas (MMcf/d)					
California	—	—	—	—	—
Utah	9.8	11.0	10.7	10.7	11.2
Colorado	7.8	7.7	8.2	7.8	8.8
Total natural gas	17.6	18.7	18.9	18.5	20.0
NGLs (MBbl/d)					
California	—	—	—	—	—
Utah	0.4	0.4	0.4	0.4	0.4
Colorado	—	—	—	—	—
Total NGLs	0.4	0.4	0.4	0.4	0.4
Total Production (MBoe/d)[2]	26.6	27.6	31.3	28.5	29.0

(1) Production represents volumes sold during the period. We also consume a portion of the natural gas we produce on lease to extract oil and gas.

(2) 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, 2020, the average prices of Brent oil and Henry Hub natural gas were $43.21 per Bbl and $2.03 per MMBtu, respectively.

CAPITAL EXPENDITURES (ACCRUAL BASIS)

	Quarter Ended December 31, 2020		Quarter Ended September 30, 2020		Quarter Ended December 31, 2019		Year Ended December 31, 2020		Year Ended December 31, 2019	
					(in thousands)					
Capital expenditures (accrual basis)	$	12,363	$	3,995	$	41,274	$	69,120	$	208,770

(1) Capital expenditures on an accrual basis excludes capitalized overhead and interest, acquisitions and asset retirement spending.

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

Adjusted Net Income (Loss) is not a measure of net income (loss), Levered Free Cash Flow is not a measure of cash flow, and Adjusted EBITDA is not a measure of either, 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, 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. 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-cash stock compensation expense and unusual, out of period and infrequent costs.

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. 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 to sustain production levels and for 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 should not be considered as an alternative to, or more meaningful than, income and liquidity measures calculated 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 and does not give effect to derivative transactions or estimated future income taxes. 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.

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).

	Quarter Ended December 31, 2020	Quarter Ended September 30, 2020	Quarter Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
	($ thousands, except per share amounts)				
Net (loss) income	$ (63,830)	$ (18,864)	$ (6,984)	$ (262,895)	$ 43,539
Add (Subtract): discrete income tax items	16,724	(2,394)	(38,653)	61,030	(38,653)
Add (Subtract):					
Losses (gains) on derivatives	43,476	(4,220)	42,159	(116,746)	44,955
Net cash received for scheduled derivative settlements	35,317	35,476	15,466	142,292	42,197
Other operating expenses	3,123	1,648	774	5,781	4,588
Impairment of oil and gas properties	—	—	51,081	289,085	51,081
Non-recurring costs	2,375	1,473	—	6,026	3,061
Reorganization items, net	—	—	—	—	426
Total additions (subtractions), net	84,291	34,377	109,480	326,438	146,308

Income tax (expense) benefit of adjustments at effective tax rate[1]	(28,605)	333	(30,654)	(79,757)	(40,966)
Adjusted Net Income (Loss)	$ 8,580	$ 13,452	$ 33,189	$ 44,816	$ 110,228
Basic EPS on Adjusted Net Income	$ 0.11	$ 0.17	$ 0.41	$ 0.56	$ 1.35
Diluted EPS on Adjusted Net Income	$ 0.11	$ 0.17	$ 0.41	$ 0.56	$ 1.35
Weighted average shares outstanding - basic	79,922	79,879	80,435	79,802	81,379
Weighted average shares outstanding - diluted	80,033	80,062	80,788	79,902	81,951

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(1) Excludes discrete income tax items from the total additions (subtractions), net line item and the tax effect the discrete income tax items have on the current rate.

ADJUSTED EBITDA AND ADJUSTED EBITDA UNHEDGED

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

	Quarter Ended December 31, 2020	Quarter Ended September 30, 2020	Quarter Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
			($ thousands)		
Net income (loss)	$ (63,830)	$ (18,864)	$ (6,984)	$ (262,895)	$ 43,539
Add (Subtract):					
Interest expense	8,308	8,391	7,871	34,295	34,234
Income tax expense (benefit)	(8,754)	(2,190)	(55,845)	(7,218)	(36,550)
Depreciation, depletion, and amortization	30,434	35,905	30,102	139,180	106,006
Impairment of oil and gas properties	—	—	51,081	289,085	51,081
(Gains) losses on derivatives	43,476	(4,220)	42,160	(116,746)	44,955
Net cash received for scheduled derivative settlements	35,317	35,476	15,466	142,292	42,197
Other operating expenses	3,123	1,648	774	5,781	4,588
Stock compensation expense	3,233	3,896	2,370	14,630	8,647
Non-recurring costs	2,375	1,473	—	6,026	3,061
Reorganization items, net	—	—	—	—	426
Adjusted EBITDA	$ 53,682	$ 61,515	$ 86,995	$ 244,430	$ 302,184
Net cash (received) paid for scheduled derivative settlements	(35,317)	(35,476)	(15,466)	(142,292)	(42,197)
Adjusted EBITDA unhedged	$ 18,365	$ 26,039	$ 71,529	$ 102,138	$ 259,987
Net cash provided by operating activities	$ 52,110	$ 57,997	$ 77,562	$ 196,529	$ 241,829
Add (Subtract):					
Cash interest payments	—	14,435	584	29,962	30,720
Cash income tax payments (refunds)	—	221	(3)	222	(2)
Non-recurring costs	2,375	1,473	—	6,026	3,061
Other changes in operating assets and liabilities	(803)	(12,611)	8,852	11,691	26,576
Adjusted EBITDA	$ 53,682	$ 61,515	$ 86,995	$ 244,430	$ 302,184
Net cash (received) paid for scheduled derivative settlements	(35,317)	(35,476)	(15,466)	(142,292)	(42,197)
Adjusted EBITDA unhedged	$ 18,365	$ 26,039	$ 71,529	$ 102,138	$ 259,987

LEVERED FREE CASH FLOW AND LEVERED FREE CASH FLOW UNHEDGED

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 December 31, 2020	Quarter Ended September 30, 2020	Quarter Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
			($ thousands)		
Adjusted EBITDA	$ 53,682	$ 61,515	$ 86,995	$ 244,430	$ 302,184
Subtract:					
Capital expenditures - accrual basis[1]	(12,363)	(3,995)	(41,274)	(69,120)	(208,770)
Interest expense	(8,308)	(8,391)	(7,871)	(34,295)	(34,234)

Cash dividends declared	—	—	(9,552)	(9,564)	(39,053)
Levered Free Cash Flow	$ 33,011	$ 49,129	$ 28,298	$ 131,451	$ 20,127
Net cash (received) paid for scheduled derivative settlements	(35,317)	(35,476)	(15,466)	(142,292)	(42,197)
Levered Free Cash Flow Unhedged	$ (2,306)	$ 13,653	$ 12,832	$ (10,841)	$ (22,070)

(1) Capital expenditures on an accrual basis excludes capitalized overhead and interest and acquisitions. Also excluded is asset retirement spending of $4.0 million, $3.7 million, and $7.2 million for the quarters ended December 31, 2020, September 30, 2020 and December 31, 2019, respectively, and $18.1 million and $26.9 million for the years ended December 31, 2020 and 2019, respectively.

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 December 31, 2020	Quarter Ended September 30, 2020	Quarter Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
	($ in thousands except per MBoe amounts)				
General and administrative expenses	$ 20,409	$ 19,173	$ 15,710	$ 77,696	$ 62,643
Subtract:					
Non-cash stock compensation expense (G&A portion)	(3,153)	(3,812)	(2,289)	(14,264)	(8,356)
Non-recurring costs	(2,375)	(1,473)	—	(6,026)	(3,061)
Adjusted General and Administrative Expenses	$ 14,881	$ 13,888	$ 13,421	$ 57,406	$ 51,226
General and administrative expenses ($/Boe)	$ 8.33	$ 7.56	$ 5.46	$ 7.45	$ 5.91
Subtract:					
Non-cash stock compensation expense ($/Boe)	(1.29)	(1.50)	(0.80)	(1.37)	(0.79)
Non-recurring costs ($/Boe)	(0.97)	(0.58)	—	(0.58)	(0.29)
Adjusted General and Administrative Expenses ($/Boe)	$ 6.07	$ 5.47	$ 4.66	$ 5.50	$ 4.84
Total MBoe	2,450	2,537	2,877	10,435	10,594

RESERVES AND PV-10

The following table summarizes our estimated proved reserves and related PV-10 as of December 31, 2020.

	Proved Reserves as of December 31, 2020(1)			
	California (San Joaquin and Ventura basins)	Utah (Uinta basin)	Colorado (Piceance basin)	Total
Proved developed reserves:				
Oil (MMBbl)	48	3	—	51
Natural Gas (Bcf)	—	22	4	26
NGLs (MMBbl)	—	1	—	1
Total (MMBoe)(2)(3)	48	7	1	56
Proved undeveloped reserves:				
Oil (MMBbl)	39	—	—	39
Natural Gas (Bcf)	—	—	—	—
NGLs (MMBbl)	—	—	—	—
Total (MMBoe)(3)	39	—	—	39
Total proved reserves:				
Oil (MMBbl)	87	3	—	90
Natural Gas (Bcf)	—	22	4	26
NGLs (MMBbl)	—	1	—	1
Total (MMBoe)(3)	87	7	1	95
PV-10 (in millions)(4)	$ 504	$ 16	—	$ 520

(1) Our estimated net reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $41.77 per Bbl Brent for oil and NGLs and $2.03 per MMBtu Henry Hub for natural gas at December 31, 2020. The volume-weighted average prices over the lives of the properties were $39.97 per Bbl of oil and condensate, $9.40 per Bbl of NGLs and $2.19 per Mcf. The prices were held constant for the lives of the properties and we took into account pricing differentials reflective of the market environment. Prices were calculated using oil and natural gas price parameters established by current guidelines of the SEC and accounting rules including adjustments by lease for quality, fuel deductions, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

(2) For proved developed reserves approximately 11% of total and 12% of oil are non-producing.

(3) 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, 2020, the average prices of Brent oil and Henry Hub natural gas were $43.21 per Bbl and $2.03 per MMBtu, respectively.

(4) For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see the table below. 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, 2020:

	At December 31, 2020
	(in millions)
California PV-10	$ 504
Utah PV-10	16
Colorado PV-10	—
Total Company PV-10	520
Less: present value of future income taxes discounted at 10%	(4)
Standardized measure of discounted future net cash flows	$ 516

The following table presents reserves changes and production for 2020:

	Total Company	**California**
	(in MMBoe)	
Extensions and discoveries	1	1
Revisions of previous estimates	(34)	(28)
Purchases of minerals[1]	—	—
Total reserves changes	(33)	(27)
Production	10	8

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(1) Purchases of minerals in place were less than 1 MMBoe.

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