Berry Corporation (bry) Reports Fourth Quarter and Full Year 2021 Financial Results; Provides 2022 Outlook

February 22, 2022

DALLAS, Feb. 22, 2022 (GLOBE NEWSWIRE) -- Berry Corporation (bry) (NASDAQ: BRY) ("Berry" or the "Company") today reported fourth quarter and full-year 2021 results. For the fourth quarter the net income was $9 million, or $0.11 per diluted share, and Adjusted Net Income(1) was $10 million, or $0.12 per diluted share. For the full year Berry's net loss was $16 million, or $0.19 per diluted share, and Adjusted Net Income(1) was $21 million, or $0.25 per diluted share. In addition, the Company's Board of Directors approved a first quarter 2022 dividend of $0.06 per share.

2021 Highlights

- Generated Adjusted EBITDA(1) of $212 million (hedged) and $300 million (unhedged) for the year
- Increased production each quarter; 2021 Q4 exit rate was 5% higher than prior year
- Reduced non-energy operating expenses by $11 million or 8% compared to prior year
- Reduced our required GHG offsets and approximately $53 million of ARO through various A&D activities
- Boosted shareholder returns with a 50% increase in quarterly fixed dividends in Q3 2021 and created new shareholder return model starting in Q1 2022 targeting top tier returns

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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.

"In 2022, under our new shareholder return model, which we are implementing in Q1 2022, we currently expect to deliver a 2022 overall cash return in the mid- to high teens at today's oil and stock prices. In terms of dollars, the 2022 cash return is expected be about 160% to 190% of the $82 million we've returned since going public three-and-a-half years ago. Like our business model, our new shareholder return model has predictability, simplicity, and transparency as its governing principles. The foundation of our return model is our base production, of which approximately 90% comes from our existing wells. Drilling new wells and workovers of existing wells are used to cover the gap between our base production and our goal of holding production flat. Combining the tremendous value of our base production with simple cost structure and current oil price strip makes our returns to shareholders easy to calculate and highly predictable," said Trem Smith, Berry board chairman and CEO.

"At Berry, we are continuing to advance our Environment, Social and Governance (ESG) initiatives while having a positive economic impact on our operations. Our planned activities include two solar projects, a carbon sequestration project, a clean water project, upgrading to low emission Tier 4 engines on many of our service rigs, and various other greenhouse gas (GHG) reduction opportunities. Beyond our ESG capital projects, we are also uniquely positioned to capture a portion of the recently announced state and federal funds to plug and abandon California's thousands of methane leaking, orphan wells with our well services business. This is just the beginning for Berry's ESG program as we continue to demonstrate our commitment to being a good corporate citizen while providing equitable and affordable energy for all Californians," continued Smith.

Fourth Quarter 2021 Results

Adjusted EBITDA(1) on a hedged basis was $60 million in the fourth quarter 2021 compared to $59 million in the third quarter 2021. This increase is largely the result of higher oil and gas prices and increased oil volumes, as well as a positive impact from the acquisition of C&J Well Services in the fourth quarter, partially offset by higher energy operating expenses.

The Company realized a 2% increase in average daily production in the fourth quarter 2021 to 27,900 boe/d, despite the divestment of our Los Angeles County Placerita assets in October, when compared to the third quarter volumes of 27,400 boe/d, as a result of its successful 2021 development program. Company-wide oil production in the fourth quarter 2021 increased 3% sequentially and California production, which is all oil and 92% of total company production, increased 4% to 22,700 mboe/d in the fourth quarter. On a pro forma basis, California production would have been 6% higher with a full quarter of the divested Placerita assets.

The Company-wide hedged realized oil price for the fourth quarter 2021 was $54.61 per bbl, a slight increase from the third quarter. California's unhedged realized oil price in the fourth quarter increased 9% to $75.90 per bbl, which was 95% of Brent.

Operating expenses, or OpEx, consists of lease operating expenses ("LOE"), third-party expenses and revenues from electricity generation, transportation, and marketing activities, as well as the effect of derivative settlements (received or paid) for gas purchases.

On a hedged basis, OpEx increased to $22.46 per boe for the fourth quarter 2021, compared to $17.18 per boe in the third quarter. This 31% increase in OpEx was entirely due to higher hedged natural gas fuel prices and lower electricity revenues due to the seasonal impact and the sale of our largest cogeneration facility with the Placerita divestiture. The higher hedged natural gas prices were due to the previous hedges expiring and the new hedges that were in place at less favorable pricing. Non-energy OpEx decreased approximately 1% on a per boe basis due to decreased well maintenance, recompletion, and workover activity in the fourth quarter.

Taxes, other than income taxes were $4.65 per boe in the fourth quarter compared to $5.33 in the third quarter. The decrease was largely due to lower property taxes for the quarter, including the impact of the Placerita divestiture.

General and administrative expenses increased 27% in the fourth quarter 2021 compared to the third quarter 2021, primarily due to C&J Well Services which was acquired on October 1, 2021. Adjusted General and Administrative Expenses[1], which excludes non-cash stock compensation costs and nonrecurring costs, increased 26% for the same reason.

The results of operations from C&J Well Services were included in Berry's consolidated results beginning the fourth quarter 2021. The C&J Well Services fourth quarter results included services revenues of $36 million, costs of services of $28 million, net income before income taxes of less than $1 million and Adjusted EBITDA of $4 million. The C&J Well Services general and administrative expenses were $4.5 million and adjusted general and administrative expenses were $3.2 million, which excludes non-recurring costs related to the acquisition and transition activity.

For the fourth quarter 2021, capital expenditures were approximately $27 million on an accrual basis and excluding acquisitions and asset retirement obligation spending, as well as C&J Well Services capital of $1 million. This was a decrease compared to $38 million for the third quarter reflecting the planned reduction in activity in the fourth quarter. Nearly all of the fourth quarter capital was focused on development activities in California. Additionally, Berry spent approximately $7 million for plugging and abandonment activities in the fourth quarter.

At December 31, 2021, the Company had liquidity of $215 million, consisting of $22 million cash on hand and $193 million available for borrowings under our 2021 RBL Facility.

Full-Year 2021 Results

Adjusted EBITDA[1] on a hedged basis was $212 million in 2021 compared to $244 million in 2020. The decrease was primarily driven by lower realized hedged prices in 2021. Additionally, taxes other than income taxes were higher in 2021. On a year-over-year basis, non-energy OpEx, energy OpEx and adjusted general and administrative expenses all experienced decreases. On an unhedged basis, Adjusted EBITDA increased to $300 million in 2021 compared to $102 million in 2020.

Average daily production for 2021 was 27,400 boe/d and increased each quarter throughout 2021, and the fourth quarter of 2021 was 5% higher than the same quarter of 2020. This is indicative of the positive response from our assets with strategic capital deployment. The year-over-year production results were impacted by the significant capital reduction in 2020 in response to the significant decline in oil price and the measured ramp up in activity in early 2021. Oil production decreased 4% in 2021 compared to 2020, however the fourth quarter 2021 exit rate was 6% higher than the fourth quarter of the prior year. As a result of the 2021 development campaign in Utah, the year-over-year production in Utah was essentially flat compared to the decline of 14% in 2020.

Company-wide hedged realized oil prices were $50.12 per bbl in 2021 compared to $56.07 per bbl in 2020. The California average unhedged oil price was $67.27 per bbl, 95% of Brent in 2021 and $40.01 per bbl in 2020, 93% of Brent.

OpEx on a hedged basis decreased $0.62 per boe from 2020 to $17.89 in 2021. Most of the cost savings was realized in non energy OpEx which decreased $0.51 per boe as a result of cost saving and efficiency measures implemented beginning in 2020 and continuing in 2021. Energy OpEx decreased $0.11 per boe due to higher electricity revenue partially offset by higher hedged fuel costs.

Taxes, other than income taxes, increased $1.24 to $4.65 per boe in 2021 compared to $3.41 in 2020. The increase was largely due to higher greenhouse gas (“GHG”) prices during 2021. GHG prices began 2021 at $18 per metric ton and increased to $32 at year-end. During 2021, Berry experienced an increase in property taxes, as well as higher severance taxes due to increased revenue driven by higher product prices.

General and administrative expenses decreased 6% in 2021 compared to 2020, primarily due to lower non-cash stock compensation costs and non-recurring cost, partially offset by increased expenses from the C&J Well Services acquisition. Excluding the impact of the C&J Well Services acquisition in the fourth quarter, general and administrative expenses decreased by approximately 12% for 2021 compared to 2020. Adjusted general and administrative expenses, which excludes non-cash stock compensation costs and nonrecurring costs, and excluding C&J Well Services were $54 million for the year ended December 31, 2021 compared to $57 million for the year ended December 31, 2020. The decrease was largely due to lower employee expenses.

The C&J Well Services results of operations beginning on the October 1, 2021, acquisition date were included in Berry's 2021 consolidated results. Such C&J Well Services results included services revenues of $36 million, costs of services of $28 million, net income before income taxes of less than $1 million and Adjusted EBITDA of $4 million. The C&J Well Services general and administrative expenses were $4.5 million and adjusted general and administrative expenses were $3.2 million, which excludes non-recurring costs related to the acquisition and transition activity.

Capital expenditures on an accrual basis and excluding acquisitions and asset retirement obligation spending totaled $132 million for 2021 (excluding C&J Well Services capital of $1 million) compared to $77 million for 2020. The increase was due primarily to the increase in drilling with 191 wells in 2021 compared to 45 in 2020. Approximately 79% of 2021 capital was directed to California oil operations and 12% to Utah operations. Additionally, Berry spent $19 million in 2021 on plugging and abandonment activities.

Proved reserves were 97 mmboe on December 31, 2021, of which 81% are located in California and where 91% of the PV-10[1] value is located. In 2021, Berry replaced 120% of our production with additional proved reserves driven by price increases and reserves extensions.

“For 2022, we plan to deploy $125 to $135 million of capital, excluding approximately $8 million for C&J Well Services, which should keep our production flat. We expect a substantial improvement in our cash flows due to improved market pricing and oil hedge position compared to 2021,” stated Cary Baetz, executive vice president and chief financial officer. “We have also improved our oil intensity over the last few months and further increased the concentration of production areas. We recently sold our Colorado gas operations and purchased a Utah operation that is 88% oil. We also sold our Placerita operations in the LA Basin, which makes us exclusively a Kern County oil producer in California. The portfolio rationalization makes us now 92% oil, up from 89%.”

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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 2022 at a rate of $0.06 per share on the Company's outstanding common stock, payable on April 15, 2022 to shareholders of record at the close of business on March 15, 2022.

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 fixed dividend in future quarters, as well as additional dividends in accordance with its newly adopted shareholder returns model commencing for the first quarter of 2022.

Full-Year 2022 Guidance

Berry remains committed to a maintenance capital program in 2022 with a fundamental focus on maximizing discretionary cash flow to return to shareholders.

Full-Year 2022 Guidance	**Low**		**High**
Average Daily Production (boe/d)[1]	25,500		27,500
Non-Energy Operating Expenses ($/boe)	$13.75		$14.25
Operating Expenses ($/boe)	$20.00		$22.00
Taxes, Other than Income Taxes ($/boe)	$4.50		$5.50
Adjusted General & Administrative (G&A) expenses ($/boe)			
Development and Production Segment & Corp	$5.75		$6.25
Well Servicing and Abandonment Segment		~$1.45	
Capital Expenditures ($ millions)			
Development and Production Segment & Corp	$125		$135
Well Servicing and Abandonment Segment		~$8	
Well Servicing & Abandonment Segment Adjusted EBITDA ($mm)		~$27	

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(1) Oil production is expected to be approximately 92% of total.

The guidance stated above assumes CalGEM continues to issue new drilling permits and certain other regulatory permits and approvals, as they have indicated they will.

Earnings Conference Call

Berry will host a conference call February 23, 2022 to discuss these results:

Live Call Date:	Wednesday, February 23, 2022
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:	CORRECTION - 6097724

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 9, 2022
Replay Dial-in:	855-859-2056 from the U.S.
	404-537-3406 from international locations
Replay Passcode:	CORRECTION - 6097724

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 onshore, low geologic risk, long-lived conventional oil reserves in the San Joaquin basin of California, with newly acquired well servicing and abandonment capabilities in 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 our 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; our new shareholder return model and the payment of any 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 the implementation of additional requirements for the regulatory approval and permitting process; 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; the impact and duration of the ongoing COVID-19 pandemic on demand and pricing levels; and the ability to effectively deploy our ESG strategy and risks associated with initiating new projects or business in connection therewith; 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, 2021.

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, 2021	Quarter Ended September 30, 2021	Quarter Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020
			(unaudited) *($ and shares in thousands, except per share amounts)*		
Consolidated Statement of Operations Data:					
Revenues and other:					
Oil, natural gas and natural gas liquids sales	$ 181,377	$ 161,058	$ 93,811	$ 625,475	$ 378,663
Service revenue	35,840	—	—	35,840	—
Electricity sales	6,308	12,371	6,724	35,636	25,813
(Losses) gains on oil and gas sales derivatives	(16,378)	(30,864)	(39,617)	(156,399)	117,781
Marketing revenues	834	732	351	3,921	1,426
Other revenues	105	117	97	477	150
Total revenues and other	208,086	143,414	61,366	544,950	523,833
Expenses and other:					
Lease operating expenses	67,292	60,930	49,621	236,048	186,348
Cost of services	28,339	—	—	28,339	—
Electricity generation expenses	3,660	7,128	5,422	23,148	16,608
Transportation expenses	1,758	1,806	1,559	6,897	6,938
Marketing expenses	825	715	344	3,811	1,380
General and administrative expenses	22,357	17,614	20,409	73,106	77,696
Depreciation, depletion and amortization	38,903	35,902	30,434	144,495	139,180
Impairment of oil and gas properties	—	—	—	—	289,085
Taxes, other than income taxes	11,920	13,420	10,858	46,500	35,572
Losses (gains) on natural gas purchase derivatives	15,772	(14,980)	3,859	(38,577)	1,035
Other operating (income) expenses	(1,726)	3,986	3,123	3,101	5,781
Total expenses and other	189,100	126,521	125,629	526,868	759,623
Other (expenses) income:					
Interest expense	(7,451)	(7,810)	(8,308)	(31,964)	(34,295)
Other, net	(91)	(5)	(13)	(247)	(28)
Total other (expenses) income	(7,542)	(7,815)	(8,321)	(32,211)	(34,323)
Income (loss) before income taxes	11,444	9,078	(72,584)	(14,129)	(270,113)
Income tax expense (benefit)	2,619	(758)	(8,754)	1,413	(7,218)
Net income (loss)	$ 8,825	$ 9,836	$ (63,830)	$ (15,542)	$ (262,895)

Net earnings (loss) per share:										
Basic	$	0.11	$	0.12	$	(0.80)	$	(0.19)	$	(3.29)
Diluted	$	0.11	$	0.12	$	(0.80)	$	(0.19)	$	(3.29)
Weighted-average common shares outstanding - basic		80,007		80,242		79,922		80,209		79,802
Weighted-average common shares outstanding - diluted		84,011		82,898		79,922		80,209		79,802
Adjusted Net Income[1]	$	10,204	$	11,536	$	8,580	$	21,072	$	44,816
Weighted-average common shares outstanding - diluted		84,011		82,898		80,033		83,496		79,902
Diluted earnings per share on Adjusted Net Income	$	0.12	$	0.14	$	0.11	$	0.25	$	0.56
Adjusted EBITDA[1]	$	60,395	$	59,324	$	53,682	$	212,146	$	244,430
Adjusted EBITDA unhedged[1]	$	93,816	$	76,946	$	18,365	$	299,771	$	102,138
Levered Free Cash Flow[1]	$	20,473	$	8,692	$	31,215	$	31,166	$	124,091
Levered Free Cash Flow Unhedged[1]	$	53,894	$	26,314	$	(4,102)	$	118,791	$	(18,201)
Adjusted General and Administrative Expenses[1]	$	16,870	$	13,442	$	14,881	$	57,015	$	57,406
Effective Tax Rate, including discrete items		23%		(8) %		12%		(10) %		3%
Cash Flow Data:										
Net cash provided by operating activities	$	40,230	$	22,399	$	52,110	$	122,488	$	196,529
Net cash used in investing activities	$	(58,251)	$	(50,024)	$	(19,098)	$	(168,787)	$	(93,620)
Net cash used in financing activities	$	(4,857)	$	(9,132)	$	(75)	$	(18,975)	$	(22,352)

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

		December 31, 2021		December 31, 2020
		(unaudited) *($ and shares in thousands)*		
Balance Sheet Data:				
Total current assets	$	147,498	$	154,491
Total property, plant and equipment, net	$	1,301,349	$	1,258,084
Total current liabilities	$	187,149	$	175,306
Long-term debt	$	394,566	$	393,480
Total stockholders' equity	$	692,648	$	714,036
Outstanding common stock shares as of		80,007		79,929

The following table represents selected financial information for the periods presented regarding the Company's business segments on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the financial information for the Company on a consolidated basis. Berry acquired C&J Well Services on October 1, 2021 and the results of their operations were included in Berry's consolidated results beginning the fourth quarter 2021.

	Year Ended December 31, 2021							
	Development & Production		Well Servicing and Abandonment		Corporate/Eliminations		Consolidated Company	
	(unaudited) *(in thousands)*							
Revenues - excluding hedges	$	665,509	$	35,840	$	—	$	701,349
Net income (loss) before income taxes	$	82,826	$	1	$	(96,956)	$	(14,129)
Adjusted EBITDA	$	251,146	$	4,310	$	(43,310)	$	212,146
Capital expenditures	$	129,479	$	1,029	$	2,211	$	132,719
Total assets	$	1,450,157	$	81,093	$	(74,771)	$	1,456,479

SUMMARY BY AREA

The following table shows a summary by area of our selected historical financial and operating information for our development and production operations.

	California (San Joaquin and Ventura basins)[3]		Utah (Uinta basin)		Colorado (Piceance basin)[4]	
	Year Ended December 31, 2021	Year Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020
			(unaudited) *($ in thousands, unless noted otherwise)*			
Oil, natural gas and natural gas liquids sales	$ 540,782	$ 335,642	$ 69,968	$ 37,481	$ 14,705	$ 5,537
Operating income (loss) [1]	$ 74,247	$ (7,915)	$ 30,128	$ (126,289)	$ 11,570	$ (357)
Depreciation, depletion, and amortization (DD&A)	$ 138,969	$ 130,388	$ 1,795	$ 7,058	$ 152	$ 324
Impairment of oil and gas properties	$ —	$ 163,879	$ —	$ 125,206	$ —	$ —
Average daily production (mboe/d)	22.0	22.9	4.2	4.3	1.2	1.3
Production (oil % of total)	100%	100%	51%	50%	2%	2%
Realized sales prices:						
Oil (per bbl)	$ 67.27	$ 40.01	$ 59.49	$ 34.81	$ 53.22	$ 24.01
NGLs (per bbl)	$ —	$ —	$ 36.64	$ 12.57	$ —	$ —
Gas (per mcf)	$ —	$ —	$ 4.94	$ 2.22	$ 5.76	$ 1.87
Capital expenditures[2]	$ 104,485	$ 65,456	$ 16,289	$ 1,247	$ 1	$ 206
Total proved reserves (mmboe)	79	87	14	7	4	1

(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.
(3) Includes production for Placerita properties, in the Ventura basin, though the end of October 2021 when they were divested. These properties had average daily production in 2021 of over 800 boe/d prior to the sale.
(4) Our properties in Colorado were in the Piceance basin, all of which were all divested in January 2022.

COMMODITY PRICING

	Quarter Ended December 31, 2021	Quarter Ended September 30, 2021	Quarter Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020
Weighted Average Realized Prices					
Oil without hedge ($/bbl)	$ 75.11	$ 69.01	$ 41.38	$ 66.57	$ 39.56
Effects of scheduled derivative settlements ($/bbl)	$ (20.50)	$ (14.66)	$ 15.03	$ (16.45)	$ 16.51
Oil with hedge ($/bbl)	$ 54.61	$ 54.35	$ 56.41	$ 50.12	$ 56.07
Natural gas ($/mcf)	$ 5.60	$ 4.29	$ 2.78	$ 5.27	$ 2.08
NGLs ($/bbl)	$ 47.45	$ 40.88	$ 16.78	$ 36.64	$ 12.57
Index Prices					
Brent oil ($/bbl)	$ 79.66	$ 73.23	$ 45.26	$ 70.95	$ 43.21
WTI oil ($/bbl)	$ 76.89	$ 70.63	$ 42.66	$ 67.90	$ 39.59
Kern, Delivered natural gas ($/mmbtu)[1]	$ 5.65	$ 5.75	$ 3.38	$ 5.65	$ 2.46
Henry Hub natural gas ($/mmbtu)[2]	$ 4.75	$ 4.35	$ 2.52	$ 3.89	$ 2.03

(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 February 11, 2022, we had the following crude oil production and gas purchases hedges.

	Q1 2022	Q2 2022	Q3 2022	Q4 2022	FY 2023	FY 2024
Brent						
Swaps						
Hedged volume (bbls)	976,500	1,117,500	1,104,000	1,104,000	3,055,750	732,000

Weighted-average price ($/bbl)	$ 69.79	$ 71.87	$ 71.84	$ 71.84	$ 71.55	$ 61.78
Put Spreads						
Long $50/$40 Put Spread hedged volume (bbls)	405,000	409,500	414,000	414,000	2,555,000	1,647,000
Short $50/$40 Put Spread hedged volume (bbls)	45,000	45,500	46,000	46,000	365,000	366,000
Collar						
Purchased Puts hedged volume (bbls)	270,000	—	—	—	1,095,000	—
Weighted-average price ($/bbl)	$ 40.00	$ —	$ —	$ —	$ 40.00	$ —
Sold hedged volume (bbls)	270,000	—	—	—	1,095,000	—
Weighted-average price ($/bbl)	$ 80.00	$ —	$ —	$ —	$ 106.33	$ —
Henry Hub						
Purchased Puts						
Hedged volume (mmbtu)	1,800,000	—	—	—	—	—
Weighted-average price ($/mmbtu)	$ 2.75	$ —	$ —	$ —	$ —	$ —
Purchased Calls						
Hedged volume (mmbtu)	2,700,000	2,730,000	2,760,000	2,760,000	10,950,000	9,150,000
Weighted-average price ($/mmbtu)	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00
Sold Puts						
Hedged volume (mmbtu)	2,700,000	2,730,000	2,760,000	2,760,000	10,950,000	9,150,000
Weighted-average price ($/mmbtu)	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75

OPERATING EXPENSES

	Quarter Ended December 31, 2021	Quarter Ended September 30, 2021	Quarter Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020
			(unaudited) *($ in thousands except per boe amounts)*		
Expenses:					
Lease operating expenses	$ 67,292	$ 60,930	$ 49,621	$ 236,048	$ 186,348
Electricity generation expenses	3,660	7,128	5,422	23,148	16,608
Electricity sales	(6,308)	(12,371)	(6,724)	(35,636)	(25,813)
Transportation expenses	1,758	1,806	1,559	6,897	6,938
Transportation sales	(105)	(117)	(97)	(477)	(150)
Marketing expenses	825	715	344	3,811	1,380
Marketing revenues	(834)	(732)	(351)	(3,921)	(1,426)
Derivative settlements (received) paid for gas purchases(1)	(8,650)	(14,095)	(3,090)	(50,897)	9,298
Total operating expenses(2)	$ 57,638	$ 43,264	$ 46,684	$ 178,973	$ 193,183
Expenses per boe:(2)					
Lease operating expenses	$ 26.23	$ 24.20	$ 20.25	$ 23.60	$ 17.86
Electricity generation expenses	1.43	2.83	2.21	2.31	1.59
Electricity sales	(2.46)	(4.91)	(2.74)	(3.56)	(2.47)
Transportation expenses	0.69	0.72	0.64	0.69	0.66
Transportation sales	(0.05)	(0.05)	(0.04)	(0.05)	(0.01)
Marketing expenses	0.32	0.28	0.14	0.38	0.13
Marketing revenues	(0.33)	(0.29)	(0.14)	(0.39)	(0.14)
Derivative settlements (received) paid for gas purchases	(3.37)	(5.60)	(1.26)	(5.09)	0.89
Total operating expenses(2)	$ 22.46	$ 17.18	$ 19.06	$ 17.89	$ 18.51
Total unhedged operating expenses(1)	$ 25.83	$ 22.78	$ 20.32	$ 22.98	$ 17.62
Total non-energy operating expenses(3)	$ 13.41	$ 13.59	$ 14.35	$ 13.12	$ 13.63
Total energy operating expenses(4)	$ 9.05	$ 3.59	$ 4.70	$ 4.77	$ 4.88
Total mboe	2,566	2,519	2,450	10,004	10,435

(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, 2021	Quarter Ended September 30, 2021	Quarter Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020
Net Oil, Natural Gas and NGLs Production Per Day[1]:					
Oil (mbbl/d)					
California[2]	22.7	21.8	21.2	22.0	22.9
Utah	2.1	2.3	2.1	2.2	2.1
Colorado[3]	—	—	—	—	—
Total oil	24.8	24.1	23.3	24.2	25.0
Natural gas (mmcf/d)					
California	—	—	—	—	—
Utah	10.0	10.7	9.8	10.2	10.7
Colorado[3]	6.4	6.9	7.8	6.9	7.8
Total natural gas	16.4	17.6	17.6	17.1	18.5
NGLs (mbbl/d)					
California	—	—	—	—	—
Utah	0.4	0.4	0.4	0.4	0.4
Colorado[3]	—	—	—	—	—
Total NGLs	0.4	0.4	0.4	0.4	0.4
Total Production (mboe/d)[2]	27.9	27.4	26.6	27.4	28.5

(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) Includes production for Placerita properties though the end of October 2021 when they were divested. These properties had average daily production in 2021 of over 800 boe/d prior to the sale.
(3) Our properties in Colorado were in the Piceance basin, all of which were all divested in January 2022.

CAPITAL EXPENDITURES (ACCRUAL BASIS)

	Quarter Ended December 31, 2021	Quarter Ended September 30, 2021	Quarter Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020
			(unaudited) *(in thousands)*		
Capital expenditures (accrual basis)[1,2]	$ 27,673	$ 38,016	$ 14,159	$ 132,719	$ 76,480

(1) Capital expenditures on an accrual basis include capitalized overhead and interest and excludes acquisitions and asset retirement spending.
(2) Capital expenditures in the quarter and year ended December 31, 2021 included $1 million for C&J Well Services which was acquired on October 1, 2021.

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, unusual 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 unusual and infrequent items. We define Levered Free Cash Flow as Adjusted EBITDA less capital expenditures, interest expense and fixed dividends. We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for non-cash stock compensation expense and unusual and infrequent costs.

Adjusted Net Income (Loss) excludes the impact of unusual 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, pay fixed dividends and accelerate our asset retirement activity. 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, which is widely used by the industry to understand the present value of oil and gas companies. It 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, 2021	Quarter Ended September 30, 2021	Quarter Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020
			(unaudited) *($ thousands, except per share amounts)*		
Net income (loss)	$ 8,825	$ 9,836	$ (63,830)	$ (15,542)	$ (262,895)
Add: discrete income tax items	581	—	16,724	581	61,030
Add (Subtract):					
Losses (gains) on derivatives	32,150	15,885	43,476	117,822	(116,746)
Net cash (paid) received for scheduled derivative settlements	(33,421)	(17,622)	35,317	(87,625)	142,292
Other operating (income) expenses	(1,726)	3,986	3,123	3,101	5,781
Impairment of oil and gas properties	—	—	—	—	289,085
Non-recurring costs	2,030	705	2,375	2,735	6,026
Total (subtractions) additions, net	(967)	2,954	84,291	36,033	326,438
Income tax benefit (expense) of adjustments at effective tax rate[1]	1,765	(1,254)	(28,605)	—	(79,757)
Adjusted Net Income	$ 10,204	$ 11,536	$ 8,580	$ 21,072	$ 44,816
Basic EPS on Adjusted Net Income	$ 0.13	$ 0.14	$ 0.11	$ 0.26	$ 0.56
Diluted EPS on Adjusted Net Income	$ 0.12	$ 0.14	$ 0.11	$ 0.25	$ 0.56
Weighted average shares outstanding - basic	80,007	80,242	79,922	80,209	79,802
Weighted average shares outstanding - diluted	84,011	82,898	80,033	83,496	79,902

(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, 2021	Quarter Ended September 30, 2021	Quarter Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020
			(unaudited) *($ thousands)*		
Net income (loss)	$ 8,825	$ 9,836	$ (63,830)	$ (15,542)	$ (262,895)
Add (Subtract):					
Interest expense	7,451	7,810	8,308	31,964	34,295
Income tax expense (benefit)	2,619	(758)	(8,754)	1,413	(7,218)
Depreciation, depletion, and amortization	38,903	35,902	30,434	144,495	139,180
Impairment of oil and gas properties	—	—	—	—	289,085
Losses (gains) on derivatives	32,150	15,885	43,476	117,822	(116,746)
Net cash (paid) received for scheduled derivative settlements	(33,421)	(17,622)	35,317	(87,625)	142,292
Other operating (income) expenses	(1,726)	3,986	3,123	3,101	5,781
Stock compensation expense	3,564	3,580	3,233	13,783	14,630
Non-recurring costs	2,030	705	2,375	2,735	6,026
Adjusted EBITDA	$ 60,395	$ 59,324	$ 53,682	$ 212,146	$ 244,430
Net cash paid (received) for scheduled derivative settlements	33,421	17,622	(35,317)	87,625	(142,292)
Adjusted EBITDA unhedged	$ 93,816	$ 76,946	$ 18,365	$ 299,771	$ 102,138
Net cash provided by operating activities	$ 40,230	$ 22,399	$ 52,110	$ 122,488	$ 196,529
Add (Subtract):					
Cash interest payments	97	14,189	—	29,211	29,962
Cash income tax payments	405	294	—	699	222
Non-recurring costs	2,030	705	2,375	2,735	6,026
Other changes in operating assets and liabilities	17,633	21,737	(803)	57,013	11,691
Adjusted EBITDA	$ 60,395	$ 59,324	$ 53,682	$ 212,146	$ 244,430
Net cash paid (received) for scheduled derivative settlements	33,421	17,622	(35,317)	87,625	(142,292)
Adjusted EBITDA unhedged	$ 93,816	$ 76,946	$ 18,365	$ 299,771	$ 102,138

Adjusted EBITDA is the measure reported to the chief operating decision maker (CODM) for purposes of making decisions about allocating resources to and assessing performance of each segment. EBITDA represents 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 unusual and infrequent items.

	Year Ended December 31, 2021			
	Development & Production	Well Servicing and Abandonment	Corporate/Eliminations	Consolidated Company
			(unaudited) *(in thousands)*	
Adjusted EBITDA reconciliation to net income (loss):				
Net income (loss)	$ 82,825	$ 1	$ (98,368)	$ (15,542)
Add (Subtract):				
Interest expense	—	—	31,964	31,964
Income tax expense	—	—	1,413	1,413
Depreciation, depletion, and amortization	136,915	2,974	4,606	144,495
Losses on derivatives	117,822	—	—	117,822
Net cash paid for scheduled derivative settlements	(87,625)	—	—	(87,625)
Other operating expenses	109	—	2,992	3,101
Stock compensation expense	1,100	—	12,683	13,783
Non-recurring costs	—	1,335	1,400	2,735
Adjusted EBITDA	$ 251,146	$ 4,310	$ (43,310)	$ 212,146

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, 2021	Quarter Ended September 30, 2021	Quarter Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020
			(unaudited) *($ thousands)*		
Adjusted EBITDA	$ 60,395	$ 59,324	$ 53,682	$ 212,146	$ 244,430
Subtract:					
Capital expenditures - accrual basis(1)	(27,673)	(38,016)	(14,159)	(132,719)	(76,480)
Interest expense	(7,451)	(7,810)	(8,308)	(31,964)	(34,295)
Fixed cash dividends declared	(4,798)	(4,806)	—	(16,297)	(9,564)
Levered Free Cash Flow(2)	$ 20,473	$ 8,692	$ 31,215	$ 31,166	$ 124,091
Net cash paid (received) for scheduled derivative settlements	33,421	17,622	(35,317)	87,625	(142,292)
Levered Free Cash Flow Unhedged	$ 53,894	$ 26,314	$ (4,102)	$ 118,791	$ (18,201)

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(1) Capital expenditures on an accrual basis includes capitalized overhead and interest and excludes acquisitions. Also excluded is asset retirement spending of $7 million, $5 million, $4 million for the quarters ended December 31, 2021, September 30, 2021 and December 31, 2020, respectively, and $19 million and $18 million for the years ended December 31, 2021 and 2020, 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, 2021	Quarter Ended September 30, 2021	Quarter Ended December 31, 2020	Year Ended December 31, 2021	Year Ended December 31, 2020
			(unaudited) *($ in thousands except per mboe amounts)*		
General and administrative expenses	$ 22,357	$ 17,614	$ 20,409	$ 73,106	$ 77,696
Subtract:					
Non-cash stock compensation expense (G&A portion)	(3,457)	(3,467)	(3,153)	(13,356)	(14,264)
Non-recurring costs	(2,030)	(705)	(2,375)	(2,735)	(6,026)
Adjusted General and Administrative Expenses	$ 16,870	$ 13,442	$ 14,881	$ 57,015	$ 57,406
Well servicing and abandonment segment	$ 3,193	$ —	$ —	$ 3,193	$ —
Development and production segment, and corporate	$ 13,677	$ 13,442	$ 14,881	$ 53,822	$ 57,406
Development and production segment, and corporate ($/boe)	$ 5.33	$ 5.34	$ 6.07	$ 5.38	$ 5.50
Total mboe	2,566	2,519	2,450	10,004	10,435

RESERVES AND PV-10

The following table summarizes our estimated proved reserves and related PV-10 as of December 31, 2021.

	Proved Reserves as of December 31, 2021(1)			
	California (San Joaquin and Ventura basins)	Utah (Uinta basin)	Colorado (Piceance basin)	Total
Proved developed reserves:				
Oil (mmbbl)	47	6	—	53
Natural Gas (bcf)	—	35	25	60
NGLs (mmbbl)	—	1	—	1

Total (mmboe)[2][3]	47	13	4	64
Proved undeveloped reserves:				
Oil (mmbbl)	32	1	—	33
Natural Gas (bcf)	—	2	—	2
NGLs (mmbbl)	—	—	—	—
Total (mmboe)[3]	32	1	—	33
Total proved reserves:				
Oil (mmbbl)	79	7	—	86
Natural Gas (bcf)	—	37	25	62
NGLs (mmbbl)	—	1	—	1
Total (mmboe)[3]	79	14	4	97
PV-10 (in millions)[4]	$ 1,374	$ 124	$ 15	$ 1,513

(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 $69.47 per bbl Brent for oil and NGLs and $3.64 per mmbtu Henry Hub for natural gas at December 31, 2021. The volume-weighted average prices over the lives of the properties were $65.10 per Bbl of oil and condensate, $36.08 per Bbl of NGLs and $3.98 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 10% of total and 11% 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, 2021, the average prices of Brent oil and Henry Hub natural gas were $70.95 per bbl and $3.89 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, 2021:

	At December 31, 2021
	(in millions)
California PV-10	$ 1,374
Utah PV-10	124
Colorado PV-10	15
Total Company PV-10	1,513
Less: present value of future income taxes discounted at 10%	(280)
Standardized measure of discounted future net cash flows	$ 1,233

The following table presents reserves changes and production for 2021:

	Total Company	**California**
	(in mmboe)	
Extensions and discoveries	3	1
Revisions of previous estimates	9	(1)
Purchases of minerals[1]	—	—
Sales of minerals[2]	—	—
Total reserves changes	12	—
Production	10	8

(1) Purchases of minerals in place were less than 1 mmboe.
(2) Sales of minerals in place were less than 1 mmboe.

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