Berry Corporation Reports Fourth Quarter and Full Year 2023 Financial Results

March 6, 2024

DALLAS, March 06, 2024 (GLOBE NEWSWIRE) -- Berry Corporation (bry) (NASDAQ: BRY) ("Berry" or the "Company") announced fourth quarter and full-year 2023 results. For the fourth quarter 2023, Berry's net income was $63 million, or $0.81 per diluted share, Adjusted Net Income [(1)] was $10 million, or $0.13 per diluted share, and cash flows from operating activities were $79 million. For the full year 2023, Berry's net income was $37 million, or $0.48 per diluted share, Adjusted Net Income[(1)] was $39 million, or $0.51 per diluted share, and cash flows from operating activities were $199 million.

Fourth Quarter 2023 Highlights

- Delivered Adjusted EBITDA[(1)] of $70 million and Adjusted Free Cash Flow[(1)] of $55 million
- Declared total fixed and variable dividends of $0.26 per share, a 24% increase over third quarter 2023
- Acquired highly synergistic working interest in Kern County, CA at year-end
- Produced 25,900 boe/d supported by development program and accretive acquisitions

2023 Highlights

- Delivered $65 million of shareholder returns, or 33% of cash flow from operating activities, consisting of:
  - $0.73 per share fixed and variable dividends (inclusive of dividends to be paid in March 2024) and
  - 1.4 million shares repurchased, or 2% of current shares outstanding
- Generated Adjusted EBITDA[(1)] of $268 million
- Generated cash flows from operating activities of $199 million and Adjusted Free Cash Flow[(1)] of $97 million
- Produced 25,400 boe/d, at the top of updated guidance, on lower capital expenditures
- Completed 2023 with zero lost time incidents
- Lower G&A compared to 2022, including 4% reduction in Adjusted G&A[(1)]
- 2023 year-end reserves of 103 million boe with California reserve replacement ratio of 176%[(1)] from field extensions and acquisitions, offsetting the impact of production and lower pricing

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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.

"2023 was a solid year for Berry in light of a lower energy price environment. We delivered top-tier dividends to our shareholders, maintained production levels essentially flat with lower capital expenditures than planned, and expanded our production base and future cash flow with two financially accretive bolt-on acquisitions," said Fernando Araujo, Berry's Chief Executive Officer. "Our full-year average production of 25,400 boe/day was primarily driven by our innovative reservoir management practices with additional contribution from our successful drilling program, which was focused on sidetracks in 2023, our robust workover campaign and the impact from the Macpherson acquisition at the end of the third quarter."

He continued, "For 2024, our strategy is unchanged with a focus to deliver sustainable free cash flow. We will seek to enhance value in our current asset base through cost reductions and maintaining flat production with the mid-point of our 2024 annual guidance. Note that our 2024 development program and guidance does not depend on obtaining new drill permits, which are currently constrained by ongoing litigation challenging Kern County's Environmental Impact Review (EIR) for CEQA compliance purposes. We will continue to seek scale and growth through bolt-ons or other opportunities in and outside of California, all while being mindful of optimizing our capital structure."

Fourth Quarter 2023 Results

Net income in the fourth quarter 2023 was $63 million compared with a loss of $45 million in the third quarter largely driven by the positive impact of improved derivative valuations and related income tax effects, partially offset by lease operating expenses, which includes fuel gas costs for our California steam operations, which increased 13% in the fourth quarter mostly because of higher natural gas (fuel) costs and higher utility costs. Adjusted net income was $10 million and $12 million in the fourth and third quarters of 2023, respectively. Adjusted EBITDA was $70 million in both of the fourth and third quarters of 2023. GHG prices increased consistently throughout 2023 beyond expectations. This had an unexpected effect on Adjusted EBITDA and earnings per share.

The Company's average daily production in the fourth quarter 2023 increased 2% to 25,900 boe/d, compared to third quarter volumes. Company-wide oil production in the fourth quarter 2023 increased 3% sequentially and California production, which consists solely of oil and comprises 83% of total company production, increased 5% to 21,500 mboe/d in the fourth quarter. These increases were largely driven by the impact from the acquisition of Macpherson Energy Corporation (the "Macpherson Acquisition") at the end of the third quarter.

Company-wide realized oil price, including hedging effects, was $72.65 per bbl for the fourth quarter 2023 compared to $73.13 per bbl in the third quarter 2023. Excluding hedging effects, California's average realized oil prices were $77.74 per bbl in the fourth quarter 2023, 94% of Brent, and

$79.98 per bbl in the third quarter 2023, 93% of Brent.

Lease operating expenses, which includes fuel gas costs for our California steam operations, increased 13% in the fourth quarter 2023 from the third quarter 2023, mostly as a result of higher natural gas (fuel) costs and higher utility costs.

Taxes, other than income taxes decreased 12% in the fourth quarter 2023 compared to the third quarter 2023 mainly due to lower severance expense and GHG allowance requirements, partially offset by increased GHG prices quarter over quarter which rose consistently throughout 2023 beyond expectations.

General and administrative expenses ("G&A") remained flat in the fourth quarter 2023 compared to the third quarter 2023. Adjusted General and Administrative Expenses(1), which excludes non-cash stock compensation costs and non-recurring costs, increased 7% in the fourth quarter 2023 compared to the third quarter 2023 due to higher costs related to year-end payroll tax and benefit true-ups, and insurance cost increases.

The net income for the well servicing and abandonment business, C&J Well Services, remained flat at $3 million in the fourth quarter 2023 compared to the third quarter 2023.

For the fourth quarter 2023, capital expenditures were approximately $16 million, excluding acquisitions, asset retirement obligation spending and $1 million of well servicing and abandonment segment capital. This represented a 36% increase in capital expenditures compared to the third quarter 2023, mainly due to an increase in drilling, facilities, and workover costs in the fourth quarter. Additionally, Berry spent approximately $3 million for plugging and abandonment activities in the fourth quarter 2023.

Full-Year 2023 Results

Net income was $37 million in 2023 compared to $250 million in 2022. Adjusted EBITDA was $268 million in 2023 compared to $380 million in 2022. The decreases were primarily driven by lower oil prices and volumes, higher GHG costs included in taxes, other than income taxes and higher lease operating expenses excluding fuel, partially offset by lower fuel costs driven by lower fuel consumption. Net income changes also included the positive overall impact of improved derivative valuation and income taxes of $18 million compared to a benefit of $42 million in the prior year due to the utilization of net operating losses and tax credits. Adjusted free cash flow declined by $102 million on lower earnings.

The Company's average daily production for the full year 2023 was 25,400 boe/d compared to 26,100 boe/d in 2022. Company-wide oil production in 2023 was 23,500 bbl/d, accounting for 93% of total Company production, with California production contributing 20,700 boe/d or 81% of total production. Overall production decreased 3% principally due to reduced drilling and workover activity, along with natural base decline, partially offset by production from the Macpherson Acquisition in September 2023.

Company-wide realized oil prices, including hedging effects, were $71.67 per bbl in 2023 compared to $77.59 per bbl in 2022. Excluding hedging effects, California average realized oil prices were $76.89 per bbl in 2023 and $93.40 per bbl, in 2022, each 94% of Brent.

Lease operating expenses, which includes fuel costs for our California steam operations, increased 5% due to higher outside services and lease maintenance costs, partially offset by lower fuel costs. Fuel consumption decreased 12% compared to 2022, which resulted in decreased fuel costs of 8%, net of a 4% increase in average natural gas prices. Lease operating expenses excluding fuel increased 12%, due to higher outside services and lease maintenance costs, mostly weather related in the first quarter 2023, as well as increased power costs driven by higher rates.

Electricity generation expenses and sales decreased 68% and 50%, respectively, in 2023 compared to 2022, due to lower volumes sold resulting from operating one of our cogeneration facilities for a portion of the year compared to running it all of 2022 to maximize the margin efficiency of these facilities. Fuel costs included in lease operating expenses and electricity generation expenses exclude the effects of natural gas derivative settlements.

Taxes, other than income taxes, increased 47% in 2023 compared to 2022, largely from increases in GHG expense due to higher GHG emission prices in a volatile California carbon allowance market, partially offset by lower GHG emissions. GHG prices increased consistently throughout 2023 beyond expectations. This had an unexpected effect on Adjusted EBITDA and earnings per share.

General and administrative expenses decreased by approximately $1 million to $96 million in 2023 compared to 2022 due to a decrease in professional services. Adjusted General and Administrative Expenses, which excludes non-cash stock compensation costs and non-recurring costs, decreased by 4%, primarily due to cost saving initiatives implemented in early 2023.

The net income for the well servicing and abandonment business, C&J Well Services, was $13 million for 2023, compared to $15 million for 2022, primarily due to a decline in California drilling activity.

For 2023, capital expenditures were approximately $67 million, excluding acquisitions, asset retirement obligation spending and $6 million of well servicing and abandonment capital, a 54% decrease compared to the prior year. The reduction in development activity was generally made in connection with the Macpherson Acquisition in September 2023. The capital budget was adjusted to reflect the reduced need for drilling activities on the legacy Berry assets due to the addition of producing assets, allowing Berry to meet production targets while reducing drilling, workover and other activities on the legacy Berry assets. In connection with the closing of the Macpherson Acquisition in September 2023, a total of $35 million was reallocated from the 2023 capital expenditures budget to fund a portion of the purchase price. Additionally, the Company spent approximately $18 million for plugging and abandonment activities in 2023.

At December 31, 2023, the Company had liquidity of $171 million, consisting of $5 million cash and $166 million available for borrowings under the Company's revolving credit facilities.

Proved reserves were 103 mmboe at December 31, 2023, of which 87% are located in California, which is also where approximately 97% of the PV-10(1) value is located. In 2023, Berry replaced 176% of its California production and 19% of its total Company production, with additional proved reserves, from field extensions and acquisitions, offsetting the impact of production and lower pricing.

"We delivered solid financial and operational results in a period of declining energy prices and generated 2023 operating cash flows of $199 million, as well as $97 million of Adjusted Free Cash Flow, more than half of which, $55 million, was attributable to the fourth quarter," said Mike Helm, Berry's Chief Financial Officer. "For 2023, we returned $65 million to shareholders, including $55 million in the form of fixed and variable dividends. These cash returns resulted in a top-tier sector total dividend yield of approximately 10% for our shareholders. We also completed $10 million in stock repurchases, or about 2% of outstanding shares. Highlighting our prudent cash management, before the end of the fourth quarter, we paid down the RBL balance that was drawn in the third quarter in connection with the closing of the Macpherson Acquisition. We then utilized about $30 million of our RBL at year end to fund our second bolt-on acquisition."

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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

In February 2024, the Company's Board of Directors approved a fixed cash dividend of $0.12 per share, as well as a variable cash dividend of $0.14 per share, based on the results of the fourth quarter 2023. Both dividends are payable on March 25, 2024, to shareholders of record at the close of business on March 15, 2024. Cash dividends based on 2023 results totaled $0.73 per share, as noted in the table below.

2023 Dividends

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year-to-Date
Fixed Dividends	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.48
Variable Dividends(1)	—	0.02	0.09	0.14	0.25
Total	$ 0.12	$ 0.14	$ 0.21	$ 0.26	$ 0.73

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(1) Variable Dividends are declared the quarter following the period of results (the period used to determine the variable divided based on the shareholder return model). The table notes total dividends earned in each quarter. In February 2024, the Board of Directors approved a $0.14 per share variable dividend based on the results for the three months ended December 31, 2023.

Full-Year 2024 Guidance

Berry's 2024 capital program reflects management's prior experience with the constraints imposed by the current permitting litigation impacting Kern County, with an underlying commitment to maximize Adjusted Free Cash Flow and shareholder value. Our current plan is based on 2024 production that is essentially flat to 2023. Berry's current capital program for 2024 focuses on sidetracks, workovers and other activities related to existing wellbores. The Company expects to benefit from a full year of production from the assets acquired in the Macpherson Acquisition and another bolt-on acquisition completed at the end of 2023, which should help keep our production essentially flat in 2024. As a result of the ongoing regulatory uncertainty in California impacting the permitting process in Kern County where all of our California assets are located, the capital program has been prepared based on the assumption that we will not receive additional new drill permits in California in 2024, but that we will continue to timely receive the other permits and approvals needed for planned activities, in addition to the permits we already have in hand. However, should there be favorable changes to the permitting process we are well prepared to take advantage of the opportunities.

In 2024, the Company expects to continue to focus on debt and leverage, including looking at opportunistically refinancing the senior notes due February 2026, if market conditions allow. The Company also expects to reduce general and administrative expenses, as well as operating costs, primarily energy costs which is reflected in the 2024 guidance.

The Company has oil hedges for more than 80% of its expected 2024 oil production, while approximately 70% of the expected production is hedged with swaps with an average strike price of $77.97 per barrel Brent. The Company has gas purchase hedges for approximately three quarters of its expected 2024 gas demand, approximately 96% of this position is swaps with an average strike of $3.99 per mmbtu.

Full-Year 2024 Guidance	**Low**		**High**
Average Daily Production (boe/d)(1)	24,600		25,800
Expenses from field operations ($/boe)(2)	$26.50		$29.50
E&P non-production revenues ($/boe)(3)	$1.80		$2.00
Natural gas purchase hedge settlements ($/boe)(4)(5)	$0.60		$0.90
Taxes, Other than Income Taxes ($/boe)	$6.50		$7.50
Adjusted General & Administrative (G&A) expenses ($/boe)(6)(7)			
E&P Segment & Corp	$5.85		$6.25
Well Servicing and Abandonment Segment	$1.30		$1.50
Capital Expenditures ($ millions)(8)	$95		$110
Well Servicing & Abandonment Segment Adjusted EBITDA ($ millions)	$16		$24

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(1) Oil production is expected to be approximately 93% of total.
(2) Expenses from field operations include lease operating expenses, electricity generation expenses, transportation expense, and marketing expenses.
(3) E&P non-production revenues include sales from electricity, transportation, and marketing activities.
(4) Natural gas purchase hedge settlements is the cash (received) or paid from these derivatives on a per boe basis.
(5) Based on natural gas hedge positions and basis differentials as of December 31, 2023, and the Henry Hub gas price of $3.00 per mmbtu.
(6) Adjusted General & Administrative expenses and Well Servicing and Abandonment Segment Adjusted EBITDA are non-GAAP financial measures. The Company does not provide a reconciliation of these measures because the Company believes such reconciliation would imply a degree of precision and certainty that could be confusing to investors and is unable to reasonably predict certain items included in or excluded from the

GAAP financial measures without unreasonable efforts. This is due to the inherent difficulty of forecasting the timing or amount of various items that have not yet occurred and are out of the Company's control or cannot be reasonably predicted. Non-GAAP forward-looking measures provided without the most directly comparable GAAP financial measures may vary materially from the corresponding GAAP financial measures.
(7) See further discussion and reconciliation in "Non-GAAP Financial Measures and Reconciliations".
(8) Total company capital expenditures, including E&P segment, well servicing & abandonment segment and corporate.

Earnings Conference Call

The Company will host a conference call to discuss these results:

Call Date: Wednesday, March 6, 2024
Call Time: 11:00 a.m. Eastern Time / 10:00 a.m. Central Time / 8:00 a.m. Pacific Time

Join the live listen-only audio webcast at https://edge.media-server.com/mmc/p/7kymzcmg or at https://bry.com/category/events. Accompanying slides will also be available at the time of the call at www.bry.com.

If you would like to ask a question on the live call, please preregister at any time using the following link:
https://register.vevent.com/register/BI4cf49100fcd44636a09625e75442bc53

Once registered, you will receive the dial-in numbers and a unique PIN number. You may then dial-in or have a call back. When you dial in, you will input your PIN and be placed into the call. If you register and forget your PIN or lose your registration confirmation email, you may simply re-register and receive a new PIN.

A web based audio replay will be available shortly after the broadcast and will be archived at
https://ir.bry.com/reports-resources or visit https://edge.media-server.com/mmc/p/7kymzcmg or
https://bry.com/category/events

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 oil and gas reserves. We operate in two business segments: (i) exploration and production ("E&P") and (ii) well servicing and abandonment. Our E&P assets are located in California and Utah, are characterized by high oil content and are predominantly located in rural areas with low population. Our California assets are in the San Joaquin basin (100% oil), while our Utah assets are in the Uinta basin (60% oil and 40% gas). We operate our well servicing and abandonment segment in California. More information can be found at the Company's website at *www.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 (including, but not limited to, Adjusted Free Cash Flow); financial and operating, results; capital program and development and production plans; operations and business strategy; potential acquisition and other strategic opportunities; reserves; hedging activities; capital expenditures; return of capital; our shareholder return model and the payment of future dividends; future repurchases of stock or debt; future reduction or refinancing of existing debt; capital investments, recovery factors; projected accretion to financial and production results; projected synergies related to the Macpherson Acquisition; anticipated increases to free cash flow and shareholder returns; our capital expenditures and leverage profile; 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 financial position, financial and operating results, liquidity, cash flows (including, but not limited to, Adjusted Free Cash Flow) and business prospects.

Berry cautions you that these forward-looking statements are subject to all of the risks and uncertainties incident to acquisition transactions and 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 with respect to existing and/or new requirements in 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, production and other operating risks; effects of competition; uncertainties inherent in estimating natural gas and oil reserves and in projecting future rates of production; our ability to replace our reserves through exploration and development activities or strategic transactions; cash flow and access to capital; the timing and funding of development expenditures; environmental, health and safety risks; effects of hedging arrangements; potential shut-ins of production due to lack of downstream demand or storage capacity; disruptions to, capacity constraints in, or other limitations on the third-party transportation and market takeaway infrastructure (including pipeline systems) that deliver our oil and natural gas and other processing and transportation considerations; epidemics or pandemics, including the effects of related public health concerns and the impact of actions that may be taken by governmental authorities and other third parties in response to a pandemic; the ability to effectively deploy our ESG strategy and risks associated with initiating new projects or business in connection therewith; our ability to successfully integrate the Macpherson assets into our operations; we fail to identify risks or liabilities related to Macpherson, its operations or assets; our inability to achieve anticipated synergies; our ability to successfully execute other strategic bolt-on acquisitions; overall domestic and global political and economic conditions; the imposition of tariffs or trade or other economic sanctions, political instability or armed conflict in oil and gas producing regions, including the ongoing conflict in Ukraine, the Israel-Hamas conflict, or a prolonged recession; inflation levels and government efforts to reduce inflation, including increased interest rates and volatility in financial markets and banking; changes in tax laws; information technology failures or cyberattacks 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, 2023 and subsequent filings with the SEC.

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 responsibility 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, 2023	Quarter Ended September 30, 2023	Quarter Ended December 31, 2022	Year Ended December 31, 2023	Year Ended December 31, 2022
		(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	$ 172,439	$ 172,611	$ 188,442	$ 669,110	$ 842,449
Service revenue	40,746	45,511	46,792	178,554	181,400
Electricity sales	2,905	3,849	8,284	15,277	30,833
Gains (losses) on oil and gas sales derivatives	83,918	(103,282)	(48,872)	40,006	(137,109)
Marketing revenues	—	—	—	—	289
Other revenues	319	113	37	513	479
Total revenues and other	300,327	118,802	194,683	903,460	918,341
Expenses and other:					
Lease operating expenses	67,342	59,842	87,601	316,726	302,321
Cost of services	32,783	35,806	35,010	141,771	142,819
Electricity generation expenses	1,827	1,479	5,199	7,079	21,839
Transportation expenses	1,260	1,089	1,021	4,486	4,564
Marketing expenses	—	—	—	—	299
Acquisition costs	284	2,082	—	3,338	—
General and administrative expenses	20,729	20,987	26,926	95,873	96,439
Depreciation, depletion and amortization	40,937	39,729	39,509	160,542	156,847
Taxes, other than income taxes	15,826	17,980	14,341	57,973	39,495
Losses (gains) on natural gas purchase derivatives	21,397	(8,425)	(41,460)	26,386	(88,795)
Other operating expenses (income)	36	(505)	(1,023)	(1,788)	3,722
Total expenses and other	202,421	170,064	167,124	812,386	679,550
Other (expenses) income:					
Interest expense	(9,680)	(9,101)	(7,646)	(35,412)	(30,917)
Other, net	(10)	(42)	(63)	(237)	(142)
Total other expenses	(9,690)	(9,143)	(7,709)	(35,649)	(31,059)
Income (loss) before income taxes	88,216	(60,405)	19,850	55,425	207,732
Income tax expense (benefit)	25,665	(15,343)	(52,114)	18,025	(42,436)
Net income (loss)	$ 62,551	$ (45,062)	$ 71,964	$ 37,400	$ 250,168
Net income (loss) per share:					
Basic	$ 0.83	$ (0.60)	$ 0.94	$ 0.49	$ 3.19
Diluted	$ 0.81	$ (0.60)	$ 0.90	$ 0.48	$ 3.03
Weighted-average common shares outstanding - basic	75,667	75,662	76,181	76,038	78,517
Weighted-average common shares outstanding - diluted	77,349	75,662	80,312	77,583	82,586

Adjusted Net Income(1)	$ 10,426	$ 11,831	$ 76,449	$ 39,230	$ 226,463
Weighted-average common shares outstanding - diluted	77,349	77,606	80,312	77,583	82,586
Diluted earnings per share on Adjusted Net Income(1)	$ 0.13	$ 0.15	$ 0.95	$ 0.51	$ 2.74
Adjusted EBITDA(1)	$ 70,036	$ 69,829	$ 77,508	$ 268,257	$ 379,948
Adjusted Free Cash Flow(1)	$ 54,824	$ 35,407	$ 55,803	$ 97,324	$ 199,766
Adjusted General and Administrative Expenses(1)	$ 17,886	$ 16,763	$ 19,410	$ 73,495	$ 76,475
Effective Tax Rate	29 %	25 %	(263)%	33 %	(20)%
Cash Flow Data:					
Net cash provided by operating activities	$ 79,018	$ 55,320	$ 105,407	$ 198,657	$ 360,941
Net cash used in investing activities	$ (48,822)	$ (68,029)	$ (54,888)	$ (175,272)	$ (164,552)
Net cash (used in) provided by financing activities	$ (42,561)	$ 21,343	$ (45,742)	$ (64,800)	$ (165,422)

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

	December 31, 2023	December 31, 2022
	(unaudited) *($ and shares in thousands)*	
Balance Sheet Data:		
Total current assets	$ 140,800	$ 218,055
Total property, plant and equipment, net	$ 1,406,612	$ 1,359,813
Total current liabilities	$ 223,182	$ 234,207
Long-term debt	$ 427,993	$ 395,735
Total stockholders' equity	$ 757,976	$ 800,485
Outstanding common stock shares as of	75,667	75,768

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.

	Year Ended December 31, 2023			
	E&P	Well Servicing and Abandonment	Corporate/ Eliminations	Consolidated Company
	(unaudited) *(in thousands)*			
Revenues(1)	$ 684,900	$ 185,767	$ (7,213)	$ 863,454
Net income (loss) before income taxes	$ 163,819	$ 13,462	$ (121,856)	$ 55,425
Capital expenditures	$ 64,844	$ 5,805	$ 2,478	$ 73,127
Total assets	$ 1,652,979	$ 68,670	$ (127,491)	$ 1,594,158

	Year Ended December 31, 2022			
	E&P	Well Servicing and Abandonment	Corporate/ Eliminations	Consolidated Company
	(unaudited) *(in thousands)*			
Revenues(1)	$ 874,190	$ 184,448	$ (3,188)	$ 1,055,450
Net income (loss) before income taxes	$ 303,178	$ 14,747	$ (110,193)	$ 207,732
Capital expenditures	$ 141,930	$ 8,455	$ 2,536	$ 152,921
Total assets	$ 1,563,251	$ 83,461	$ (15,682)	$ 1,631,030

(1) These revenues do not include hedge settlements.

COMMODITY PRICING

	Quarter Ended	Quarter Ended	Quarter Ended	Year Ended	Year Ended

	December 31, 2023	September 30, 2023	December 31, 2022	December 31, 2023	December 31, 2022
Weighted Average Realized Sales Prices					
Oil without hedges ($/bbl)	$ 76.00	$ 78.89	$ 80.61	$ 75.05	$ 91.98
Effects of scheduled derivative settlements ($/bbl)	$ (3.35)	$ (5.76)	$ (7.22)	$ (3.38)	$ (14.39)
Oil with hedges ($/bbl)	$ 72.65	$ 73.13	$ 73.39	$ 71.67	$ 77.59
Natural gas ($/mcf)	$ 4.48	$ 3.57	$ 12.02	$ 6.94	$ 7.96
NGLs ($/bbl)	$ 24.01	$ 22.54	$ 29.67	$ 24.47	$ 43.85
Purchased Natural Gas					
Purchase price, before the effects of derivative settlements ($/mmbtu)	$ 5.29	$ 4.18	$ 9.62	$ 8.21	$ 7.86
Effects of derivative settlements ($/mmbtu)	$ 0.44	$ 1.43	$ (2.28)	$ (1.79)	$ (1.74)
Purchase price, after the effects of derivative settlements ($/mmbtu)	$ 5.73	$ 5.61	$ 7.34	$ 6.42	$ 6.12
Index Prices					
Oil – Brent (bbl)	$ 82.85	$ 85.92	$ 88.63	$ 82.18	$ 99.04
Oil – WTI (bbl)	$ 78.49	$ 81.99	$ 82.51	$ 77.61	$ 94.39
Natural gas (mmbtu) – SoCal Gas city-gate (1)	$ 6.25	$ 7.10	$ 9.71	$ 10.96	$ 8.38
Natural gas (mmbtu) – Northwest, Rocky Mountains(2)	$ 4.53	$ 3.40	$ 7.54	$ 8.28	$ 6.95
Natural gas (mmbtu) – Henry Hub(2)	$ 2.74	$ 2.59	$ 5.55	$ 2.53	$ 6.45

(1) The natural gas we purchase to generate steam and electricity is primarily based on Rockies price indexes, including transportation charges, as we currently purchase a substantial majority of our gas needs from the Rockies, with the balance purchased in California. SoCal Gas city-gate Index is the relevant index used only for the portion of gas purchases in California. Beginning in the first quarter of 2023, we are purchasing a majority of our fuel gas in the Rockies, most of the purchases made in California utilize the SoCal Gas city-gate index, whereas prior to this shift the predominant index for California purchases were Kern, Delivered.
(2) Most of our gas purchases and gas sales in the Rockies are predicated on the Northwest, Rocky Mountains index, and to a lesser extent based on Henry Hub.

Natural gas prices and differentials are strongly affected by local market fundamentals, availability of transportation capacity from producing areas and seasonal impacts. Our key exposure to gas prices is in our costs. We purchase substantially more natural gas for our California steamfloods and cogeneration facilities than we produce and sell in the Rockies. In May 2022, we began purchasing most of our gas in the Rockies and transporting it to our California operations using our Kern River pipeline capacity. We buy approximately 48,000 mmbtu/d in the Rockies, and the remainder comes from California markets. The volume purchased in California fluctuates and averaged 5,000 mbbtu/d in 2023, and 12,000 mmbtu/d in 2022.The natural gas we purchase in the Rockies is shipped to our operations in California to help limit our exposure to California fuel gas purchase price fluctuations. We strive to further minimize the variability of our fuel gas costs for our steam operations by hedging a significant portion of our gas purchases. Additionally, the negative impact of higher gas prices on our California operating expenses is partially offset by higher gas sales for the gas we produce and sell in the Rockies. The Kern capacity allows us to purchase and sell natural gas at the same pricing indices.

CURRENT HEDGING SUMMARY

As of February 29, 2024, we had the following crude oil production and gas purchases hedges:

	Q1 2024	Q2 2024	Q3 2024	Q4 2024	FY 2025	FY 2026
Brent - Crude Oil Production						
Swaps						
Hedged volume (bbls)	1,536,118	1,611,294	1,481,749	1,438,656	2,669,125	1,881,768
Weighted-average price ($/bbl)	$ 78.95	$ 78.97	$ 76.87	$ 76.94	$ 75.22	$ 70.84
Sold Calls(1)						
Hedged volume (bbls)	122,000	91,000	92,000	92,000	2,486,127	1,251,500
Weighted-average price ($/bbl)	$ 105.00	$ 105.00	$ 105.00	$ 105.00	$ 91.11	$ 85.53
Purchased Puts (net)(2)						
Hedged volume (bbls)	318,500	318,500	322,000	322,000	2,486,127	1,251,500
Weighted-average price ($/bbl)	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 58.53	$ 60.00
Sold Puts (net)(2)						
Hedged volume (bbls)	45,500	45,500	46,000	46,000	—	—
Weighted-average price ($/bbl)	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ —	$ —
NWPL - Natural Gas Purchases(3)						

Swaps						
Hedged volume (mmbtu)	3,040,000	3,640,000	3,680,000	3,680,000	6,080,000	—
Weighted-average price ($/mmbtu)	$ 4.11	$ 3.96	$ 3.96	$ 3.96	$ 4.27	$ —
HH - Natural Gas Purchases(3)						
Purchased Calls						
Hedged volume (mmbtu)	600,000	—	—	—	—	—
Weighted-average price ($/mmbtu)	$ 3.38	$ —	$ —	$ —	$ —	$ —
Gas Basis Differentials						
NWPL/HH - Natural Gas Purchases(3)						
Hedged volume (mmbtu)	600,000	—	—	—	—	—
Weighted-average price ($/mmbtu)	$ 4.10	$ —	$ —	$ —	$ —	$ —

(1) Purchased calls and sold calls with the same strike price have been presented on a net basis.
(2) Purchased puts and sold puts have been presented on a net basis.
(3) The term “NWPL” is defined as Northwest Rocky Mountain Pipeline. The term “HH” is defined as Henry Hub.

GAINS (LOSSES) ON DERIVATIVES

A summary of gains and losses on the derivatives included on the statements of operations is presented below:

	Quarter Ended December 31, 2023	Quarter Ended September 30, 2023	Quarter Ended December 31, 2022	Year Ended December 31, 2023	Year Ended December 31, 2022
			(unaudited) (in thousands)		
Realized gains (losses) on commodity derivatives:					
Realized (losses) on oil and gas sales derivatives	$ (7,405)	$ (12,304)	$ (16,031)	$ (28,917)	$ (126,176)
Realized (losses) gains on natural gas purchase derivatives	(2,211)	(7,128)	12,527	34,812	38,153
Total realized (losses) gains on derivatives	$ (9,616)	$ (19,432)	$ (3,504)	$ 5,895	$ (88,023)
Unrealized gains (losses) on commodity derivatives:					
Unrealized gains (losses) on oil and gas sales derivatives	$ 91,323	$ (90,978)	$ (32,841)	$ 68,923	$ (10,933)
Unrealized (losses) gains on natural gas purchase derivatives	(19,186)	15,553	28,933	(61,198)	50,642
Total unrealized gains (losses) on derivatives	$ 72,137	$ (75,425)	$ (3,908)	$ 7,725	$ 39,709
Total gains (losses) on derivatives	$ 62,521	$ (94,857)	$ (7,412)	$ 13,620	$ (48,314)

E&P FIELD OPERATIONS

	Quarter Ended December 31, 2023	Quarter Ended September 30, 2023	Quarter Ended December 31, 2022	Year Ended December 31, 2023	Year Ended December 31, 2022
			(unaudited) ($ in per boe amounts)		
Expenses from field operations					
Lease operating expenses	$ 28.25	$ 25.73	$ 36.95	$ 34.21	$ 31.72
Electricity generation expenses	0.77	0.64	2.19	0.76	2.29
Transportation expenses	0.53	0.47	0.43	0.48	0.48
Marketing expenses	—	—	—	—	0.03
Total	$ 29.55	$ 26.84	$ 39.57	$ 35.45	$ 34.52
Cash settlements received for gas purchase hedges	$ 0.93	$ 3.06	$ (5.28)	$ (3.76)	$ (4.00)
E&P non-production revenues					
Electricity sales	$ 1.22	$ 1.65	$ 3.49	$ 1.65	$ 3.24
Transportation sales	0.13	0.05	0.02	0.06	0.05

	Quarter Ended December 31, 2023	Quarter Ended September 30, 2023	Quarter Ended December 31, 2022	Year Ended December 31, 2023	Year Ended December 31, 2022
Marketing revenue	—	—	—	—	0.03
Total	$ 1.35	$ 1.70	$ 3.51	$ 1.71	$ 3.32

Overall, management assesses the efficiency of our E&P field operations by considering core E&P operating expenses together with our cogeneration, marketing and transportation activities. In particular, a core component of our E&P operations in California is steam, which we use to lift heavy oil to the surface. We operate several cogeneration facilities to produce some of the steam needed in our operations. In comparing the cost effectiveness of our cogeneration plants against other sources of steam in our operations, management considers the cost of operating the cogeneration plants, including the cost of the natural gas purchased to operate the facilities, against the value of the steam and electricity used in our E&P field operations and the revenues we receive from sales of excess electricity to the grid. We strive to minimize the variability of our fuel gas costs for our California steam operations with natural gas purchase hedges. Consequently, the efficiency of our E&P field operations are impacted by the cash settlements we receive or pay from these derivatives. We also have contracts for the transportation of fuel gas from the Rockies which has historically been cheaper than the California markets. With respect to transportation and marketing, management also considers opportunistic sales of incremental capacity in assessing the overall efficiencies of E&P operations.

Lease operating expenses include fuel, labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Electricity generation expenses include the portion of fuel, labor, maintenance, and tools and supplies from two of our cogeneration facilities allocated to electricity generation expense; the remaining cogeneration expenses are included in lease operating expense. Transportation expenses relate to our costs to transport the oil and gas that we produce within our properties or move it to the market. Marketing expenses mainly relate to natural gas purchased from third parties that moves through our gathering and processing systems and then sold to third parties. Electricity revenue is from the sale of excess electricity from two of our cogeneration facilities to a California utility company under long-term contracts at market prices. These cogeneration facilities are sized to satisfy the steam needs in their respective fields, but the corresponding electricity produced is more than the electricity that is currently required for the operations in those fields. Transportation sales relate to water and other liquids that we transport on our systems on behalf of third parties and marketing revenues represent sales of natural gas purchased from and sold to third parties.

PRODUCTION STATISTICS

	Quarter Ended December 31, 2023	Quarter Ended September 30, 2023	Quarter Ended December 31, 2022	Year Ended December 31, 2023	Year Ended December 31, 2022
Net Oil, Natural Gas and NGLs Production Per Day[(1)]:					
Oil (mbbl/d)					
California	21.5	20.5	21.1	20.7	21.3
Utah	2.5	2.7	3.0	2.8	2.7
Total oil	24.0	23.2	24.1	23.5	24.0
Natural gas (mmcf/d)					
California	—	—	—	—	—
Utah	7.8	9.5	7.8	8.8	9.6
Colorado[(2)]	—	—	—	—	0.6
Total natural gas	7.8	9.5	7.8	8.8	10.2
NGLs (mbbl/d)					
California	—	—	—	—	—
Utah	0.6	0.5	0.4	0.4	0.4
Total NGLs	0.6	0.5	0.4	0.4	0.4
Total Production (mboe/d)[(3)]	25.9	25.3	25.8	25.4	26.1

(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) In January 2022, we divested all of our natural gas properties in Colorado.
(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, 2023, the average prices of Brent oil and Henry Hub natural gas were $82.18 per bbl and $2.53 per mmbtu respectively.

CAPITAL EXPENDITURES

	Quarter Ended December 31, 2023	Quarter Ended September 30, 2023	Quarter Ended December 31, 2022	Year Ended December 31, 2023	Year Ended December 31, 2022
			(unaudited) *(in thousands)*		
Capital expenditures[(1)(2)]	$ 17,003	$ 13,596	$ 50,398	$ 73,127	$ 152,921

(1) Capital expenditures include capitalized overhead and interest and excludes acquisitions and asset retirement spending.

(2) Capital expenditures in the quarters ended December 31, 2023, September 30, 2023 and December 31, 2022 included $1 million, $2 million and $5 million, respectively, for the well servicing and abandonment business. Capital expenditures in the years ended December 31, 2023 and December 31, 2022 included approximately $6 million and $8 million, respectively, for the well servicing and abandonment business.

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

Adjusted Net Income (Loss) is not a measure of net income (loss), Adjusted Free Cash Flow is not a measure of cash flow, and Adjusted EBITDA is not a measure of either net income (loss) or cash flow, in all cases, as determined by GAAP. Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) 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 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. 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. We also use Adjusted EBITDA in planning our capital expenditure allocation to sustain production levels and to determine our strategic hedging needs aside from the hedging requirements of the 2021 RBL Facility.

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 statutory tax rate. 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. We believe Adjusted Net Income (Loss) is useful to investors because it reflects how management evaluates the Company’s ongoing financial and operating performance from period-to-period after removing certain transactions and activities that affect comparability of the metrics and are not reflective of the Company’s core operations. We believe this also makes it easier for investors to compare our period-to-period results with our peers.

We define Adjusted Free Cash Flow, which is a non-GAAP financial measure, as cash flow from operations less regular fixed dividends and maintenance capital. Maintenance capital represents the capital expenditures needed to maintain substantially the same volume of annual oil and gas production and is defined as capital expenditures, excluding, when applicable, (i) E&P capital expenditures that are related to strategic business expansion, such as acquisitions and divestitures of oil and gas properties and any exploration and development activities to increase production beyond the prior year's annual production volumes, (ii) capital expenditures in our well servicing and abandonment segment, (iii) corporate expenditures that are related to ancillary sustainability initiatives and/or (iv) other expenditures that are discretionary and unrelated to maintenance of our core business. Management believes Adjusted Free Cash Flow may be useful in an investor analysis of our ability to generate cash from operating activities from our existing oil and gas asset base after maintaining the existing production volumes of that asset base to return capital to stockholders, fund further business expansion through acquisitions or investments in our existing asset base to increase production volumes and pay other non-discretionary expenses. Management also uses Adjusted Free Cash Flow as the primary metric to plan for future growth.

Adjusted Free Cash Flow does not represent the total increase or decrease in our cash balance, and it should not be inferred that the entire amount of Adjusted Free Cash Flow is available for variable dividends, debt or share repurchases, strategic acquisitions or other growth opportunities, or other discretionary expenditures, since we have mandatory debt service requirements and other non-discretionary expenditures that are not deducted from this measure.

We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for non-cash stock compensation expense and unusual and infrequent costs. Management believes Adjusted General and Administrative Expenses is useful because it allows us to more effectively compare our performance from period to period. We believe Adjusted General and Administrative Expenses is useful to investors because it reflects how management evaluates the Company’s ongoing general and administrative expenses from period-to-period after removing non-cash stock compensation, as well as unusual or infrequent costs that affect comparability of the metrics and are not reflective of the Company’s administrative costs. We believe this also makes it easier for investors to compare our period-to-period results with our peers.

While Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses are non-GAAP measures, the amounts included in the calculation of Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) 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. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. Our computations of Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) and Adjusted General and Administrative Expenses may not be comparable to other similarly titled measures used by other companies. Adjusted EBITDA, Adjusted Free Cash Flow, Adjusted Net Income (Loss) 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 EBITDA

The following tables present reconciliations of the GAAP financial measures of net income (loss) and net cash provided (used) by operating activities to the non-GAAP financial measure of Adjusted EBITDA, as applicable, for each of the periods indicated.

	Quarter Ended December 31, 2023	Quarter Ended September 30, 2023	Quarter Ended December 31, 2022	Year Ended December 31, 2023	Year Ended December 31, 2022
			(unaudited) *(in thousands)*		
Adjusted EBITDA reconciliation:					
Net income (loss)	$ 62,551	$ (45,062)	$ 71,964	$ 37,400	$ 250,168
Add (Subtract):					
Interest expense	9,680	9,101	7,646	35,412	30,917
Income tax expense (benefit)	25,665	(15,343)	(52,114)	18,025	(42,436)
Depreciation, depletion, and amortization	40,937	39,729	39,509	160,542	156,847
Stock compensation expense	3,020	3,018	4,350	14,356	16,973
(Gains) losses on derivatives	(62,521)	94,857	7,412	(13,620)	48,314
Net cash (paid) received for scheduled derivative settlements	(9,616)	(19,432)	(3,504)	5,895	(88,023)
Acquisition costs[1]	284	2,082	—	3,338	—
Non-recurring costs[2]	—	1,384	3,268	8,697	3,466
Other operating expenses (income)	36	(505)	(1,023)	(1,788)	3,722
Adjusted EBITDA	$ 70,036	$ 69,829	$ 77,508	$ 268,257	$ 379,948
Net cash provided by operating activities	$ 79,018	$ 55,320	$ 105,407	$ 198,657	$ 360,941
Add (Subtract):					
Cash interest payments	1,794	15,065	311	32,251	29,792
Cash income tax payments	525	2,087	828	3,282	3,633
Acquisition costs[1]	284	2,082	—	3,338	—
Non-recurring costs[2]	—	1,384	3,268	8,697	3,466
Changes in operating assets and liabilities - working capital[3]	(11,070)	(5,114)	(31,003)	25,654	(21,446)
Other operating (income) expenses - cash portion[4]	(515)	(995)	(1,303)	(3,622)	3,562
Adjusted EBITDA	$ 70,036	$ 69,829	$ 77,508	$ 268,257	$ 379,948

(1) Consists of costs related to the Macpherson Acquisition.
(2) In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter, and costs related to the settlement of shareholder litigation in the third quarter. In 2022, non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter and executive transition costs in the fourth quarter.
(3) Changes in other assets and liabilities consists of working capital and various immaterial items.
(4) Represents the cash portion of other operating (income) expenses from the income statement, net of the non-cash portion in the cash flow statement.

ADJUSTED FREE CASH FLOW

The following table presents a reconciliation of the GAAP financial measure of operating cash flow to the non-GAAP financial measure of Adjusted Free Cash Flow for each of the periods indicated.

	Quarter Ended December 31, 2023	Quarter Ended September 30, 2023	Quarter Ended December 31, 2022	Year Ended December 31, 2023	Year Ended December 31, 2022
			(unaudited) *(in thousands)*		
Adjusted Free Cash Flow reconciliation:					
Net cash provided by operating activities[1]	$ 79,018	$ 55,320	$ 105,407	$ 198,657	$ 360,941
Subtract:					
Maintenance capital[2]	(15,114)	(10,833)	(45,047)	(64,844)	(141,930)
Fixed dividends[3]	(9,080)	(9,080)	(4,557)	(36,489)	(19,245)
Adjusted Free Cash Flow	$ 54,824	$ 35,407	$ 55,803	$ 97,324	$ 199,766

(1) On a consolidated basis.
(2) Maintenance capital is the capital required to keep annual production substantially flat, and is calculated as follows:

	Quarter Ended December 31,	Quarter Ended September 30,	Quarter Ended December 31,	Year Ended December 31,	Year Ended December 31,

	2023	2023	2022	2023	2022
			(unaudited) *(in thousands)*		
Consolidated capital expenditures[(a)]	$ (17,003)	$ (13,596)	$ (50,398)	$ (73,127)	$ (152,921)
Excluded items[(b)]	1,889	2,763	5,351	8,283	10,991
Maintenance capital[(c)]	$ (15,114)	$ (10,833)	$ (45,047)	$ (64,844)	$ (141,930)

(a) Capital expenditures include capitalized overhead and interest and excludes acquisitions and asset retirement spending.
(b) Comprised of the capital expenditures in the Company's E&P segment that are related to strategic business expansion, such as acquisitions of oil and gas properties and any exploration and development activities to increase production beyond the prior year's annual production volumes and capital expenditures in the Company's well servicing and abandonment segment and corporate expenditures that are related to ancillary sustainability initiatives or other expenditures that are discretionary and unrelated to maintaining flat production in the Company's E&P business. For the three months ended December 31, 2023, September 30, 2023, December 31, 2022, and the years ended December 31, 2023 and 2022, we excluded approximately $1 million, $2 million, $5 million, $6 million and $8 million of capital expenditures in the Company's well servicing and abandonment segment, respectively, which was substantially all used for sustainability initiatives or other expenditures that are discretionary and unrelated to maintenance of the Company's core business. For the three months ended December 31, 2023, September 30, 2023, December 31, 2022, and the years ended December 31, 2023 and 2022, we excluded approximately $0.5 million, $0.7 million, $0.5 million, $2 million and $3 million of corporate capital expenditures, respectively, which the Company determined was not related to the maintenance of baseline production.
(c) In 2024, we updated the definition of Adjusted Free Cash Flow to cash flow from operations less regular fixed dividends and capital expenditures. Adjusted Free Cash Flow for prior periods has not been retroactively adjusted for the updated definition.

(3) Represents fixed dividends declared for the periods presented.

ADJUSTED NET INCOME (LOSS)

The following table presents a reconciliation of the GAAP financial measures of net income (loss) and net income (loss) per share — diluted to the non-GAAP financial measures of Adjusted Net Income (Loss) and Adjusted Net Income (Loss) per share — diluted for each of the periods indicated.

	Quarter Ended					
	December 31, 2023		September 30, 2023		December 31, 2022	
	(in thousands)	per share - diluted	(in thousands)	per share - diluted	(in thousands)	per share - diluted
			(unaudited)			
Adjusted Net Income (Loss) reconciliation:						
Net income (loss)	$ 62,551	$ 0.81	$ (45,062)	$ (0.58)	$ 71,964	$ 0.90
Add (Subtract):						
(Gains) losses on derivatives	(62,521)	(0.81)	94,857	1.22	7,412	0.09
Net cash (paid) for scheduled derivative settlements	(9,616)	(0.12)	(19,432)	(0.25)	(3,504)	(0.04)
Other operating expenses (income)	36	—	(505)	(0.01)	(1,023)	(0.02)
Acquisition costs[(1)]	284	—	2,082	0.03	—	—
Non-recurring costs[(2)]	—	—	1,384	0.02	3,268	0.04
Total (subtractions) additions, net	(71,817)	(0.93)	78,386	1.01	6,153	0.07
Income tax benefit (expense) of adjustments[(3)]	19,692	0.25	(21,493)	(0.28)	(1,668)	(0.02)
Adjusted Net Income	$ 10,426	$ 0.13	$ 11,831	$ 0.15	$ 76,449	$ 0.95
Basic EPS on Adjusted Net Income	$ 0.14		$ 0.16		$ 1.00	
Diluted EPS on Adjusted Net Income	$ 0.13		$ 0.15		$ 0.95	
Weighted average shares of common stock outstanding - basic	75,667		75,662		76,181	
Weighted average shares of common stock outstanding - diluted	77,349		77,606		80,312	

(1) Consists of costs related to the Macpherson Acquisition.
(2) Consists of costs related to the settlement of shareholder litigation in the third quarter of 2023, and executive transition costs in the fourth quarter of 2022.
(3) The federal and state statutory rates were utilized in both 2023 and 2022.

	Year Ended

	December 31, 2023		December 31, 2022	
	(in thousands)	per share - diluted	(in thousands)	per share - diluted
		(unaudited)		
Adjusted Net Income (Loss) reconciliation:				
Net income	$ 37,400	$ 0.48	$ 250,168	$ 3.03
Add (Subtract):				
(Gains) losses on derivatives	(13,620)	(0.18)	48,314	0.59
Net cash received (paid) for scheduled derivative settlements	5,895	0.08	(88,023)	(1.07)
Other operating (income) expenses	(1,788)	(0.01)	3,722	0.04
Acquisition costs(1)	3,338	0.04	—	—
Non-recurring costs(2)	8,697	0.11	3,466	0.04
Total additions (subtractions), net	2,522	0.04	(32,521)	(0.40)
Income tax (expense) benefit of adjustments(3)	(692)	(0.01)	8,816	0.11
Adjusted Net Income	$ 39,230	$ 0.51	$ 226,463	$ 2.74
Basic EPS on Adjusted Net Income	$ 0.52		$ 2.88	
Diluted EPS on Adjusted Net Income	$ 0.51		$ 2.74	
Weighted average shares of common stock outstanding - basic	76,038		78,517	
Weighted average shares of common stock outstanding - diluted	77,583		82,586	

(1) Consists of costs related to the Macpherson Acquisition.
(2) In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter, and costs related to the settlement of shareholder litigation in the third quarter. In 2022, non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter and executive transition costs in the fourth quarter.
(3) The federal and state statutory rates were utilized in both 2023 and 2022.

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 measure of Adjusted General and Administrative Expenses for each of the periods indicated.

	Quarter Ended December 31, 2023	Quarter Ended September 30, 2023	Quarter Ended December 31, 2022	Year Ended December 31, 2023	Year Ended December 31, 2022
			(unaudited) *($ in thousands)*		
Adjusted General and Administrative Expense reconciliation:					
General and administrative expenses	$ 20,729	$ 20,987	$ 26,926	$ 95,873	$ 96,439
Subtract:					
Non-cash stock compensation expense (G&A portion)	(2,843)	(2,840)	(4,248)	(13,681)	(16,498)
Non-recurring costs(1)	—	(1,384)	(3,268)	(8,697)	(3,466)
Adjusted General and Administrative Expenses	$ 17,886	$ 16,763	$ 19,410	$ 73,495	$ 76,475
Well servicing and abandonment segment	$ 2,177	$ 2,910	$ 3,296	$ 11,171	$ 12,975
E&P segment, and corporate	$ 15,709	$ 13,853	$ 16,114	$ 62,324	$ 63,500
E&P segment, and corporate ($/boe)	$ 6.59	$ 5.96	$ 6.80	$ 6.73	$ 6.66
Total mboe	2,384	2,326	2,371	9,258	9,532

(1) In 2023, non-recurring costs included executive transition costs and workforce reduction costs in the first quarter, and costs related to the settlement of shareholder litigation in the third quarter. In 2022, non-recurring costs included legal and professional service expenses related to acquisition and divestiture activity in the first quarter and executive transition costs in the fourth quarter.

RESERVES AND PV-10

The following table summarizes our estimated proved reserves and related PV-10 as of December 31, 2023:

	Proved Reserves as of December 31, 2023[1]		
	California (San Joaquin basin)	**Utah (Uinta basin)**	**Total**
		(unaudited)	
Proved developed reserves:			
Oil (mmbbl)	46	6	52
Natural gas (bcf)	—	21	21
NGLs (mmbbl)	—	1	1
Total (mmboe)[2][3]	46	11	57
Proved undeveloped reserves:			
Oil (mmbbl)	44	2	46
Natural gas (bcf)	—	5	5
NGLs (mmbbl)	—	—	—
Total (mmboe)[3]	44	2	46
Total proved reserves:			
Oil (mmbbl)	90	8	98
Natural gas (bcf)	—	26	26
NGLs (mmbbl)	—	1	1
Total (mmboe)[3]	90	13	103
PV-10 (in millions)[4]	$ 1,977	$ 72	$ 2,049

(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 $82.84 per bbl Brent for oil and NGLs and $2.63 per mmbtu Henry Hub for natural gas at December 31, 2023. The volume-weighted average realized prices over the lives of the properties were $77.30 per bbl of oil and condensate, $26.90 per bbl of NGLs and $3.73 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 12% 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, 2023, the average prices of Brent oil and Henry Hub natural gas were $82.18 per bbl and $2.53 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, 2023:

	At December 31, 2023
	(unaudited) *(in millions)*
California PV-10	$ 1,977
Utah PV-10	72
Total Company PV-10	2,049
Less: present value of future income taxes discounted at 10%	(366)
Standardized measure of discounted future net cash flows	$ 1,683

The following table presents reserves changes and production for 2023:

	Total Company	**California**
	(unaudited) *(in mmboe)*	
Extensions and discoveries	5	5
Revisions of previous estimates	(12)	(1)
Purchases of minerals[1]	9	9
Total reserves changes	2	13

Production	(9)	(7)
Reserve replacement ratio	19 %	176 %

(1) Purchases of minerals are related to the Macpherson Acquisition and a small acquisition in Kern County in December 2023.

Contact Contact: Berry Corporation (bry) Todd Crabtree - Director, Investor Relations (661) 616-3811 ir@bry.com