Berry Corporation (BRY) Reports Strong Fourth Quarter and Full Year 2019 Results; Continues to Deliver Top Tier Industry Returns, Achieved Double Digit California Production Growth; Replaced Nearly 300% of California Reserves

February 27, 2020

DALLAS, Feb. 26, 2020 (GLOBE NEWSWIRE) -- Berry Corporation (bry) (NASDAQ: BRY) ("Berry" or the "Company") today reported an 18% increase in fourth quarter 2019 production from its California assets over the prior year fourth quarter and it replaced nearly 300% of its California proved reserves. For the full year of 2019, Berry's net income was $44 million, or $0.53 per diluted share, and Adjusted Net Income(1) was $110 million, or $1.35 per diluted share. For the fourth quarter of 2019, the net loss was $7 million, or $0.09 per diluted share, and Adjusted Net Income was $33 million, or $0.41 per diluted share. In addition, the Board approved a first quarter 2020 dividend of $0.12 per share, as it has done each quarter since becoming a public company in 2018. The Board also approved the opportunistic repurchase of an additional $50 million shares pursuant to the previously announced $100 million share repurchase program.

Highlights for the Quarter

- California production increased 18% over prior year fourth quarter and 11% sequentially
- Fourth quarter production mix was 89% oil
- Adjusted EBITDA(1) of $87 million and Unhedged Adjusted EBITDA(1) of $72 million
- Capital expenditures of $42 million with approximately 84% directed to development in California
- Repurchased 1.4 million shares in fourth quarter and nearly 5.1 million shares to date for $50 million

"We had a great fourth quarter and 2019. Our business model works and when we invest capital in development drilling, our assets respond, creating additional value. Our top tier returns and strong production and reserve profile, achieved while generating excess levered free cash flow, demonstrate the strength of our financial principles. In 2019, we grew California oil production more than 15% year over year; increased our California reserves, entirely oil, 23% before production on a year-over-year basis; and we paid $85 million to return capital to our shareholders by repurchasing 6% of our outstanding shares while continuing to pay one of the highest dividend yields in the industry. In 2020, you can expect more of the same from Berry. We are committed to generating strong oil growth on a lower capital spend; continuing our substantial return of capital and, at today's pricing, generating solid excess levered free cash flow," stated Trem Smith, Berry board chair, chief executive officer and president.

Highlights for the Full Year

- Oil production up 15% compared to prior year and comprised 87% of total production
- Adjusted EBITDA of $302 million and Unhedged Adjusted EBITDA of $260 million
- Capital expenditures of $211 million with approximately 91% directed to California assets
- Repurchased 4.6 million shares for $46 million and paid over $39 million in dividends
- Replaced nearly 300%(2) of California reserves and 159%(2) of total company PUD inventory
- Increased inventory to over 10,800 locations
- Total company PV-10(1) of over $1.8 billion, including $1.7 billion for California

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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.

(2) Please see " Non-GAAP Financial Measures and Reconciliations" later in this press release for more information on how we calculate reserve replacement ratios and total company PUD inventory replacement ratios.

Smith continued, "In California, we remain steadfast in our commitment to the state and its ambitious environmental initiatives. We have sharpened our focus on Environmental, Social, and Governance (ESG) reporting, and we are formalizing how we monitor and manage our ESG performance and engage with our stakeholders on these important issues. We believe that the oil and gas industry will remain an important part of the energy landscape for the long term. In California, specifically, that means locally producing and supplying affordable and reliable energy to ensure a safe, healthy and prosperous future for its communities and citizens, and reducing California's reliance upon imported foreign oil that comes from countries that do not share our environmental and social justice standards and expectations."

Fourth Quarter 2019 Results

Adjusted EBITDA for the fourth quarter 2019 increased to $87 million, compared to $84 million in the third quarter 2019, primarily due to increased production. Adjusted EBITDA, on an unhedged basis, was $72 million in the fourth quarter 2019 compared to $69 million in the third quarter 2019.

Levered Free Cash Flow(1) for the fourth quarter 2019 was $28 million, after $42 million of capital expenditures, $8 million of interest and $10 million of dividends declared. Additionally, the Company repurchased 1.4 million shares in the fourth quarter for approximately $11 million.

Average daily production in the fourth quarter 2019 of 31,300 Boe/d was 12% higher than the prior year fourth quarter and increased 6% compared to the third quarter 2019 driven by our development capital spending in 2019. California production of 25,500 MBoe/d for the fourth quarter 2019 was up 18% over the prior year and 11% sequentially to the third quarter 2019.

California oil prices before hedges for the fourth quarter 2019 averaged $60.20/Bbl which was 2% higher than the $59.00/Bbl realized in the third quarter 2019. Company-wide realized oil prices before hedges of $59.28/Bbl was also 2% higher in the fourth quarter 2019 compared to the third quarter 2019.

For the fourth quarter 2019, Operating Expenses ("OpEx") increased to $20.37/Boe compared to $18.90/Boe in the third quarter. This increase in OpEx was primarily due to higher hedged fuel gas price and management's continuing efforts to aggressively manage repair and maintenance activities, in particular, some inherited long-term delayed maintenance on some equipment.

Total general and administrative ("G&A") expenses for the fourth quarter decreased almost $0.60/Boe to $5.46/Boe compared to the third quarter due to increased production and year-end incentive compensation true-ups. Adjusted G&A[(1)] also decreased for the same reasons in the fourth quarter to $4.66/Boe compared to $5.13/Boe for the third quarter.

Taxes, other than income taxes were $4.16/Boe for the fourth quarter, compared to $3.40/Boe in the third quarter, largely due to increased market rates for our greenhouse gas allowance requirements.

Capital expenditures, which were largely focused on drilling in California, decreased to $42 million for the fourth quarter compared to $63 million for the third quarter, in both periods largely focused on drilling in California. Consistent with our 2019 plan, we reduced our fourth quarter drilling activity compared to the rest of the year, while we spent additional capital preparing for our 2020 capital program. In Utah, the Company drilled two wells, and completed a third well that was drilled in the prior quarter.

In addition to the proved reserve increases in California, total company proved undeveloped drilling locations increased 159% for the year. This increase was offset by the reduction in proved undeveloped reserves in its Piceance natural gas properties in Colorado, triggered by the decline in gas prices and management's intention to continue investing capital in California and Utah while this low gas price in the Colorado market persists. As a result, the Company recorded a non-cash, pre-tax asset impairment charge of $51 million in the fourth quarter. Also in the fourth quarter, the Company recorded a $37 million tax benefit related to tax credits taken in recently filed federal returns.

Full Year 2019 Results

Adjusted EBITDA increased 17% to $302 million for the full year 2019 from $258 million in 2018 primarily due to the 15% increase in oil production. This increase was partially offset by increased OpEx, G&A, taxes other than income taxes and decreased oil prices. Adjusted EBITDA, on an unhedged basis, was $260 million in 2019 compared to $296 million in 2018.

For the year, increased Adjusted EBITDA supported positive Levered Free Cash Flow of nearly $20 million, which included $211 million of capital expenditures, $34 million of interest and $39 million of dividends declared. Additionally, the Company spent approximately $46 million in the year to repurchase 4.6 million shares, or approximately 6% of outstanding shares and approximately $50 million cumulatively for the program, begun in late 2018.

Year-over-year California production increased 15%, while overall production increased 7% due to production response from the development capital spending throughout 2019 and 2018, which more than offset the natural decline of our properties and the sale of our East Texas properties in November 2018.

For 2019, California oil prices before hedges averaged $60.51/Bbl which was 8% lower than the $65.64/Bbl realized in 2018. Realized oil prices before hedges for the Company were $58.93/Bbl, a 9% decrease over 2018.

For 2019, OpEx increased to $20.32/Boe compared to $18.33/Boe in 2018. The key drivers included higher repair and maintenance expenses, decreased electricity margins from higher downtime, higher hedged fuel cost and the increased oil mix of our properties which generally have higher costs, partially offset by lower transportation expense.

G&A was $5.91/Boe for 2019 compared to $5.48/Boe for 2018. Adjusted G&A was $4.84/Boe for 2019 compared to $4.13/Boe in the prior year. G&A and Adjusted G&A Expenses increases were primarily associated with supporting the company's growth and public company status. We also invested in the continuing development of our corporate affairs department and activities whose purpose is to support our efforts and participation in the regulatory, political and legislative process primarily in California.

Taxes, other than income taxes were $3.84/Boe for 2019, compared to $3.36/Boe in 2018, due to higher greenhouse gas unit costs partially offset by lower severance taxes.

Capital expenditures totaled $211 million for 2019 compared to $148 million for 2018. Capital was largely focused on increased drilling in California, which accounted for 91% of 2019 development capital.

As of December 31, 2019, the elected commitment under Berry's reserves-based lending credit facility ("RBL Facility") was $400 million with $2 million of outstanding borrowings. The Company had $391 million available for borrowing under the RBL Facility which included $7 million of outstanding letters of credit. In February, Berry's Board of Directors approved programs to opportunistically repurchase up to $75 million of the $400 million of outstanding 7.0% 2026 Notes and another $50 million of shares.

"In 2020, we are currently targeting capital expenditures in the range of $125 million to $145 million, which we expect will result in continued annual organic production growth in the low double digits from our California assets," stated Cary Baetz, executive vice president and chief financial officer. "At current energy price levels, in combination with our hedging program, we expect to generate strong EBITDA and solid excess levered free cash flow, allowing us to continue to create shareholder value and continuing to return capital to our shareholders. Reflecting confidence in this program and the results it will generate, the Board recently approved the first quarter 2020 dividend of $0.12 per share following the approval of our budget, marking our seventh consecutive regular quarterly dividend since our 2018 initial public offering."

Full-Year 2020 Guidance

The Company expects to employ up to three drilling rigs in California during the last three quarters of 2020, and up to one rig throughout most, if not all, of the first quarter of 2020. Additionally, the Company anticipates drilling approximately 195 to 225 gross development wells during 2020, almost all of which will be in California for oil production.

Full-Year 2020 Guidance	Low		High
Average Daily Production (MBoe/d)	29.5		32.5
Oil as % of Production		~90%	
Operating Expenses ($/Boe)	$ 19.00		$ 21.00
Taxes, Other than Income Taxes ($/Boe)	$ 4.00		$ 4.50
Adjusted General & Administrative (G&A) expenses ($/Boe)	$ 4.75		$ 5.25
Capital Expenditures ($ millions)	$ 125		$ 145
New Drill Wells	195		225

Dividend Announcement

In February 2020, the Company's Board of Directors declared a regular dividend for the first quarter of 2020 at a rate of $0.12 per share on the Company's outstanding common stock. This is the Company's seventh regular quarterly dividend, and the Company intends to pay a similar dividend in future quarters, subject to Board approval.

The first quarter dividend is payable on or about April 15, 2020 to shareholders of record at the close of business on March 13, 2020.

Name Change and New Logo

In mid-February 2020, Berry introduced a new logo and shortened name to reflect the company's progressive approach to evolving and growing the business in today's dynamic oil and gas industry. This identity will be rolled out completely in the coming month. The new logo shows an intricate network of integrated components all working together to form one shape. The color gradations represent the range of competencies as well as the changing nature of the business and echo the company's commitment to health, safety and the environment. Trem Smith, Berry board chair, CEO and president said "We are proactively engaging the many forces driving our industry to maximize our assets, create value for shareholders, and support environmental goals that align with a more positive future. One of the more visible elements of our business is our publicly traded stock, and our new logo echoes the public value of the company by using our ticker symbol as an identifiable element of our brand."

Earnings Conference Call

Berry will host a conference call February 27, 2020 to discuss these results:

Live Call Date:	Thursday, February 27, 2020
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:	2697719

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

An audio replay will be available shortly after the broadcast:

Replay Dates:	Through Wednesday, March 11, 2020
Replay Dial-in:	855-859-2056 from the U.S.
	404-537-3406 from international locations
Replay Passcode:	2697719

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

About Berry Corporation (bry)

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

Forward Looking Statements

The information in this press release includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this press release that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Such statements involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Without limiting the generality of the forgoing, such statements specifically include our expectations as to our future:

- financial position,
- liquidity,
- cash flows,
- anticipated financial and operating results,
- our capital program and development and production plans,

- business strategy,
- potential acquisition opportunities,
- other plans and objectives for operations,
- maintenance capital requirements,
- expected production and costs,
- reserves,
- hedging activities,
- return of capital,
- payment of future dividends,
- future repurchases of stock or debt,
- capital investments and other guidance.

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

- volatility of oil, natural gas and natural gas liquids (NGL) prices;
- price and availability of natural gas and electricity;
- availability and the timing of required permits and approvals and our inability to meet existing or new conditions imposed on those permits and approvals;
  our ability to meet our planned drilling schedule, including our inability to obtain permits on a timely basis or at all, and our ability to successfully drill wells that produce oil and natural gas in commercially viable quantities;
- the impact of current laws and regulations, and of pending or future legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products;
- our ability to use derivative instruments to manage commodity price risk;
- inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures and to meet working capital requirements;
- the impact of environmental, health and safety, and other governmental regulations, and of current or pending or future legislation;
- uncertainties associated with estimating proved reserves and related future cash flows;
- our ability to replace our reserves through exploration and development activities;
- lower-than-expected production or reserves from development projects or higher-than-expected decline rates;
- untimely or unavailable drilling and completion equipment or crew unavailability or lack of access to necessary resources for drilling, completing and operating wells;
- our ability to make acquisitions and successfully integrate any acquired businesses;
- catastrophic events;
- market fluctuations in electricity prices and the cost of steam; and
- other material risks that appear in the Risk Factors section of our Annual Report on Form 10-K and other periodic reports filed with the Securities and Exchange Commission.

You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, continue, could, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes.

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.

TABLES FOLLOWING

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

SUMMARY OF RESULTS

	Berry Corporation (bry)				
	Quarter Ended December 31, 2019	**Quarter Ended September 30, 2019**	**Quarter Ended December 31, 2018**	**Year Ended December 31, 2019**	**Year Ended December 31, 2018**
	($ and shares in thousands, except per share amounts)				
Consolidated Statement of Operations Data:					

Revenues and other:					
Oil, natural gas and natural gas liquids sales	$ 156,336	$ 141,250	$ 142,861	$ 565,596	$ 552,874
Electricity sales	6,844	7,460	9,517	29,397	35,208
Gains (losses) on oil derivatives	(45,544)	45,509	127,160	(37,998)	(4,621)
Marketing revenues	437	413	534	2,094	2,322
Other revenues	55	40	274	316	774
Total revenues and other	118,128	194,672	280,346	559,405	586,557
Expenses and other:					
Lease operating expenses	59,529	50,957	51,308	216,294	188,776
Electricity generation expenses	4,785	3,781	6,764	19,490	20,619
Transportation expenses	2,124	2,067	2,220	8,059	9,860
Marketing expenses	403	398	716	2,073	2,140
General and administrative expenses	15,710	16,434	16,130	62,643	54,026
Depreciation, depletion, amortization and accretion	30,102	27,664	24,253	106,006	86,271
Impairment of oil and gas properties	51,081	—	—	51,081	—
Taxes, other than income taxes	11,962	9,249	7,829	40,645	33,117
(Gains) losses on natural gas derivatives	(3,385)	3,008	(4,477)	6,957	(6,357)
Other operating expenses (income)	774	(550)	(3,269)	4,588	(2,747)
Total expenses and other	173,085	113,008	101,474	517,836	385,705
Other income (expenses):					
Interest expense	(7,871)	(8,597)	(8,820)	(34,234)	(35,648)
Other, net	—	(77)	108	80	243
Total other income (expenses)	(7,871)	(8,674)	(8,712)	(34,154)	(35,405)
Reorganization items, net	—	(170)	1,498	(426)	24,690
Income (loss) before income taxes	(62,828)	72,820	171,658	6,989	190,137
Income tax expense (benefit)	(55,844)	20,171	39,890	(36,550)	43,035
Net income (loss)	(6,984)	52,649	131,768	43,539	147,102
Series A preferred stock dividends and conversion to common stock	—	—	—	—	(97,942)
Net income (loss) attributable to common stockholders	$ (6,984)	$ 52,649	$ 131,768	$ 43,539	$ 49,160
Net income (loss) per share attributable to common stockholders					
Basic[a]	$ (0.09)	$ 0.65	$ 1.56	$ 0.54	$ 0.85
Diluted[a]	$ (0.09)	$ 0.65	$ 1.56	$ 0.53	$ 0.85
Weighted-average common shares outstanding - basic[a]	80,435	80,982	84,367	81,379	57,743
Weighted-average common shares outstanding - diluted[a]	80,435	81,051	84,592	81,951	57,932
Adjusted net income (loss)[b]	$ 33,189	$ 32,760	$ 34,809	$ 110,228	$ 100,001
Weighted-average common shares outstanding - diluted	80,788	81,051	84,592	81,951	79,633
Diluted earnings per share on adjusted net income	$ 0.41	$ 0.40	$ 0.41	$ 1.35	$ 1.26
Adjusted EBITDA[b]	$ 86,995	$ 83,931	$ 81,669	$ 302,184	$ 257,924
Adjusted EBITDA unhedged[b]	$ 71,529	$ 68,778	$ 72,990	$ 259,987	$ 296,406
Levered free cash flow[b]	$ 27,695	$ 2,126	$ 9,531	$ 17,802	$ 45,787
Levered free cash flow unhedged[b]	$ 12,229	$ (13,027)	$ 852	$ (24,395)	$ 84,269
Adjusted general and administrative expenses[b]	$ 13,421	13,940	$ 11,533	$ 51,226	$ 40,668
Effective Tax Rate	89 %	28 %	23 %	(523)%	23 %
Cash Flow Data:					
Net cash provided by (used in) operating activities[c]	$ 86,036	$ 65,320	$ 94,511	$ 241,829	$ 105,471
Net cash provided by (used in) investing activities	$ (57,361)	$ (60,285)	$ (35,438)	$ (225,025)	$ (121,440)
Net cash provided by (used in) financing activities	$ (28,675)	$ (5,262)	$ (14,306)	$ (85,484)	$ 15,911

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

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

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

	Berry Corporation (bry)			
	December 31, 2019		December 31, 2018	
	($ and shares in thousands)			
Balance Sheet Data:				
Total current assets	$	100,432	$	229,022
Total property, plant and equipment, net	$	1,576,267	$	1,442,708
Total current liabilities	$	156,628	$	144,118
Long-term debt	$	394,319	$	391,786
Total equity	$	972,448	$	1,006,446
Outstanding common stock shares as of[d]		79,543		81,202

(d) At December 31, 2018, excludes 2,770,000 common stock shares negotiated with general unsecured creditors electing to settle claims in exchange for common shares subsequent to December 31, 2018.

SUMMARY BY AREA

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

	California (San Joaquin and Ventura basins)		Utah (Uinta basin)		Colorado (Piceance basin)	
	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
($ in thousands, unless noted otherwise)						
Oil, natural gas and natural gas liquids sales	$ 498,325	$ 471,802	$ 59,383	$ 65,605	$ 7,740	$ 10,657
Operating income[a]	$ 230,500	$ 185,965	$ 7,624	$ 15,066	$ (48,955)	$ 6,346
Depreciation, depletion, and amortization (DD&A)	$ 93,025	$ 72,260	$ 11,754	$ 10,420	$ 1,055	$ 646
Impairment of oil and gas properties	$ —	$ —	$ —	$ —	$ 51,081	$ —
Average daily production (MBoe/d)	22.6	19.7	5.0	5.0	1.4	1.7
Production (oil % of total)	100 %	100 %	54 %	48 %	2 %	1 %
Realized sales prices:						
Oil (per Bbl)	$ 60.51	$ 65.64	$ 45.72	$ 57.30	$ 52.36	$ 61.50
NGLs (per Bbl)	$ —	$ —	$ 17.08	$ 26.95	$ —	$ —
Gas (per Mcf)	$ —	$ —	$ 2.94	$ 2.68	$ 2.26	$ 2.75
Capital expenditures[b]	$ 191,955	$ 125,565	$ 10,229	$ 16,738	$ 603	$ 613
Total proved reserves (MMBoe)	122	106	15	19	1	18

(a) Operating income includes oil, natural gas and NGL sales, marketing revenues, other revenues, and scheduled oil derivative settlements, offset by operating expenses, general and administrative expenses, DD&A, impairment of oil and gas properties, and taxes, other than income taxes.
(b) Excludes corporate capital expenditures.

COMMODITY PRICING

	Berry Corporation (bry)				
	Quarter Ended December 31, 2019	Quarter Ended September 30, 2019	Quarter Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
Realized Prices					
Oil without hedge ($/Bbl)	$ 59.28	$ 57.92	$ 61.48	$ 58.93	$ 64.76
Effects of scheduled derivative settlements ($/Bbl)	$ 5.70	$ 7.31	$ 2.88	$ 4.68	$ (5.09)
Oil with hedge ($/Bbl)	$ 64.98	$ 65.23	$ 64.36	$ 63.61	$ 59.67
Natural gas ($/Mcf)	$ 2.60	$ 2.12	$ 3.86	$ 2.66	$ 2.74
NGLs ($/Bbl)	$ 14.60	$ 12.10	$ 20.39	$ 17.02	$ 26.74
Index Prices					
Brent oil ($/Bbl)	$ 62.42	$ 62.03	$ 68.08	$ 64.16	$ 71.69
WTI oil ($/Bbl)	$ 57.02	$ 56.33	$ 58.81	$ 57.03	$ 64.81
Kern, Delivered natural gas ($/MMBtu)[a]	$ 2.99	$ 2.50	$ 4.40	$ 3.14	$ 3.36
Henry Hub natural gas (S/MMBtu)	$ 2.40	$ 2.38	$ 3.64	$ 2.56	$ 3.15

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

CURRENT HEDGING SUMMARY

As of December 31, 2019, our positions were as follows:

	Q1 2020	Q2 2020	Q3 2020	Q4 2020	FY 2021
Fixed Price Oil Swaps (Brent):					
Hedged volume (MBbls)	1,729	1,456	1,472	1,472	730
Weighted-average price ($/Bbl)	$ 63.92	$ 64.30	$ 64.21	$ 64.21	$ 58.50
Fixed Price Oil Swaps (WTI):					
Hedged volume (MBbls)	91	30	—	—	—
Weighted-average price ($/Bbl)	$ 61.75	$ 61.75	$ —	$ —	$ —
Fixed Price Gas Purchase Swaps (Kern, Delivered):					
Hedged volume (MMBtu)	5,005,000	5,005,000	5,060,000	2,315,000	900,000
Weighted-average price ($/MMBtu)	$ 2.89	$ 2.89	$ 2.89	$ 2.79	$ 2.50
Fixed Price Gas Purchase Swaps (SoCal Citygate):					
Hedged volume (MMBtu)	455,000	455,000	460,000	155,000	—
Weighted-average price ($/MMBtu)	$ 3.80	$ 3.80	$ 3.80	$ 3.80	$ —

After December 31, 2019 we added fixed price gas purchase swaps (Kern, Delivered) of 5,000 MMBtu/d at $2.55 beginning November 2020 through October 2021.

OPERATING EXPENSES

	Berry Corporation (bry)				
	Quarter Ended December 31, 2019	Quarter Ended September 30, 2019	Quarter Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
	($ in thousands except per Boe amounts)				
Expenses:					
Lease operating expenses	$ 59,529	$ 50,957	$ 51,308	$ 216,294	$ 188,776
Electricity generation expenses	4,785	3,781	6,764	19,490	20,619
Electricity sales[1]	(6,844)	(7,460)	(9,517)	(29,397)	(35,208)
Transportation expenses	2,124	2,067	2,220	8,059	9,860
Transportation sales[1]	(55)	(40)	(274)	(316)	(774)
Marketing expenses	403	398	716	2,073	2,140
Marketing revenues[1]	(437)	(413)	(534)	(2.094)	(2,322)
Derivative settlements (received) paid for gas purchases[a]	(906)	2,088	(2,407)	1,050	(2,407)

Total operating expenses[a]	$ 58,599	$ 51,378	$ 48,276	$ 217,251	$ 180,684
Expenses per Boe:[a]					
Lease operating expenses	$ 20.69	$ 18.74	$ 19.96	$ 20.42	$ 19.16
Electricity generation expenses	1.66	1.39	2.63	1.84	2.09
Electricity sales	(2.38)	(2.74)	(3.70)	(2.77)	(3.57)
Transportation expenses	0.74	0.76	0.86	0.76	1.00
Transportation sales	(0.02)	(0.01)	(0.11)	(0.03)	(0.08)
Marketing expenses	0.14	0.15	0.28	0.20	0.22
Marketing revenues	(0.15)	(0.15)	(0.21)	(0.20)	(0.24)
Derivative settlements (received) paid for gas purchases	(0.31)	0.77	(0.94)	0.10	(0.24)
Total operating expenses (per Boe)[b]	$ 20.37	$ 18.90	$ 18.77	$ 20.32	$ 18.33
Total unhedged operating expenses[b]	$ 20.68	$ 18.13	$ 19.71	$ 20.22	$ 18.57
Total MBoe	2,877	2,719	2,571	10,594	9,855

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

(b) Total unhedged operating expenses equals total operating expenses less the derivatives settlements paid for gas purchases

PRODUCTION STATISTICS

	Berry Corporation (bry)				
	Quarter Ended December 31, 2019	**Quarter Ended September 30, 2019**	**Quarter Ended December 31, 2018**	**Year Ended December 31, 2019**	**Year Ended December 31, 2018**
Net Oil, Natural Gas and NGLs Production Per Day[a]:					
Oil (MBbl/d)					
California	25.5	23.0	21.7	22.6	19.7
Utah	2.2	2.7	2.0	2.7	2.3
Colorado	—	—	—	—	—
Total oil	27.7	25.7	23.7	25.3	22.0
Natural gas (MMcf/d)					
California	—	—	—	—	—
Utah	10.7	12.1	9.8	11.2	12.0
Colorado	8.2	8.8	9.6	8.8	10.1
East Texas[b]	—	—	2.8	—	4.2
Total natural gas	18.9	20.9	22.1	20.0	26.3
NGLs (MBbl/d)					
California	—	—	—	—	—
Utah	0.4	0.4	0.6	0.4	0.6
Colorado	—	—	—	—	—
Total NGLs	0.4	0.4	0.6	0.4	0.6
Total Production (MBoe/d)[c]	31.3	29.6	28.0	29.0	27.0

(a) Production represents volumes sold during the period.

(b) On November 30, 2018, we sold our non-core gas-producing properties and related assets located in the East Texas basin.

(c) 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, 2019, the average prices of Brent oil and Henry Hub natural gas were $64.16 per Bbl and $2.56 per Mcf, respectively, resulting in an oil-to-gas ratio of over 4 to 1 on an energy equivalent basis.

CAPITAL EXPENDITURES (ACCRUAL BASIS)

	Berry Corporation (bry)				
	Quarter Ended December 31, 2019	**Quarter Ended September 30, 2019**	**Quarter Ended December 31, 2018**	**Year Ended December 31, 2019**	**Year Ended December 31, 2018**
			(in thousands)		
Capital expenditures (accrual basis)	$ 41,877	$ 63,488	$ 53,326	$ 211,095	$ 147,831

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

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

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

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

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

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

ADJUSTED NET INCOME (LOSS)

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

	Berry Corporation (bry)				
	Quarter Ended December 31, 2019	Quarter Ended September 30, 2019	Quarter Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
	($ thousands, except per share amounts)				
Net income (loss)	$ (6,984)	$ 52,649	$ 131,768	$ 43,539	$ 147,102
Subtract: prior period income tax credits	(38,653)	—	—	(38,653)	—
Add (Subtract):					
(Gains) losses on oil and natural gas derivatives	42,159	(42,501)	(131,637)	44,955	(1,735)
Net cash received (paid) for scheduled derivative settlements	15,466	15,153	8,679	42,197	(38,482)
Other operating expenses (income)	774	(550)	(3,269)	4,588	(2,747)
Impairment of oil & gas properties	51,081	—	—	51,081	—
Restructuring and other non-recurring costs	—	219	1,414	3,061	6,773
Reorganization items, net	—	170	(1,498)	426	(24,690)
Total additions (subtractions), net	109,480	(27,509)	(126,311)	146,308	(60,881)
Income tax (expense) benefit of adjustments at effective tax rate(1)	(30,654)	7,620	29,352	(40,966)	13,780
Adjusted net income (loss)	$ 33,189	$ 32,760	$ 34,809	$ 110,228	$ 100,001
Basic EPS on adjusted net income	$ 0.41	$ 0.40	$ 0.41	$ 1.35	$ 1.73
Diluted EPS on adjusted net income	$ 0.41	$ 0.40	$ 0.41	$ 1.35	$ 1.26
Weighted average shares outstanding - basic	80,435	80,982	84,367	81,379	57,743
Weighted average shares outstanding - diluted	80,788	81,309	84,592	81,379	79,633

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(1) Excludes prior year income tax credits from the total additions (subtractions), net line item and the tax effect the prior tax credits have on the current year effective tax 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.

	Berry Corporation (bry)				
	Quarter Ended December 31, 2019	Quarter Ended September 30, 2019	Quarter Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
Net income (loss)	($ thousands)				
Add (Subtract):	$ (6,984)	$ 52,649	$ 131,768	$ 43,539	$ 147,102
Interest expense	7,871	8,597	8,820	34,234	35,648
Income tax expense	(55,845)	20,171	39,890	(36,550)	43,035

(benefit)					
Depreciation, depletion, and amortization	30,102	27,664	24,253	106,006	86,271
Impairment of oil and gas properties	51,081	—	—	51,081	—
Derivative (gains) losses	42,160	(42,501)	(131,637)	44,955	(1,735)
Net cash received (paid) for scheduled derivative settlements	15,466	15,153	8,679	42,197	(38,482)
Other operating expenses (income)	774	(550)	(3,269)	4,588	(2,747)
Stock compensation expense	2,370	2,360	3,249	8,647	6,750
Restructuring and other non-recurring costs	—	219	1,414	3,061	6,773
Reorganization items, net	—	170	(1,498)	426	(24,690)
Adjusted EBITDA	$ 86,995	$ 83,931	$ 81,669	$ 302,184	$ 257,924
Net cash (received) paid for scheduled derivative settlements	(15,466)	(15,153)	(8,679)	(42,197)	38,482
Adjusted EBITDA unhedged	$ 71,529	$ 68,778	$ 72,990	$ 259,987	$ 296,406
Net cash provided by operating activities	$ 86,036	$ 65,320	$ 94,511	$ 241,829	$ 105,471
Add (Subtract):					
Cash interest payments	584	14,864	562	30,720	19,761
Cash income tax (refunds)	(3)	—	(1,901)	(2)	(1,901)
Cash reorganization item (receipts) payments	—	—	(174)	—	832
Restructuring and other non-recurring costs	—	219	1,414	3,061	6,773
Derivative early termination payment	—	—	—	—	126,949

Other changes in operating assets and liabilities	378	3,528	(12,743)	26,576	39
Adjusted EBITDA	$ 86,995	$ 83,931	$ 81,669	$ 302,184	$ 257,924
Net cash (received) paid for scheduled derivative settlements	(15,466)	(15,153)	(8,679)	(42,197)	38,482
Adjusted EBITDA unhedged	$ 71,529	$ 68,778	$ 72,990	$ 259,987	$ 296,406

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.

	Berry Corporation (bry)				
	Quarter Ended December 31, 2019	Quarter Ended September 30, 2019	Quarter Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
			($ thousands)		
Adjusted EBITDA	$ 86,995	$ 83,931	$ 81,669	$ 302,184	$ 257,924
Subtract:					
Capital expenditures - accrual basis	(41,877)	(63,488)	(53,326)	(211,095)	(147,831)
Interest expense	(7,871)	(8,597)	(8,820)	(34,234)	(35,648)
Cash dividends declared	(9,552)	(9,720)	(9,992)	(39,053)	(28,658)
Levered Free Cash Flow	$ 27,695	$ 2,126	$ 9,531	$ 17,802	$ 45,787
Net cash (received) paid for scheduled derivative settlements	(15,466)	(15,153)	(8,679)	(42,197)	38,482
Levered Free Cash Flow Unhedged	$ 12,229	$ (13,027)	$ 852	$ (24,395)	$ 84,269

ADJUSTED GENERAL AND ADMINISTRATIVE EXPENSES

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

	Berry Corporation (bry)				
	Quarter Ended December 31, 2019	Quarter Ended September 30, 2019	Quarter Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
		($ in thousands except per MBoe amounts)			
General and administrative expenses	$ 15,710	$ 16,434	$ 16,130	$ 62,643	$ 54,026
Subtract:					
Non-recurring restructuring and other costs	—	(219)	(1,414)	(3,061)	(6,773)
Non-cash stock compensation expense	(2,289)	(2,275)	(3,183)	(8,356)	(6,585)
Adjusted general and administrative expenses	$ 13,421	$ 13,940	$ 11,533	$ 51,226	$ 40,668
General and administrative expenses ($/Boe)	$ 5.46	$ 6.04	$ 6.27	$ 5.91	$ 5.48
Subtract:					
Non-recurring restructuring and other costs ($/Boe)	—	(0.08)	(0.55)	(0.29)	(0.69)

Non-cash stock compensation expense ($/Boe)	(0.80)	(0.84)	(1.24)	(0.79)	(0.67)
Adjusted general and administrative expenses ($/Boe)	$ 4.66	$ 5.13	$ 4.49	$ 4.84	$ 4.13
Total MBoe	2,877	2,719	2,571	10,594	9,855

RESERVES AND PV-10

The following table summarizes our estimated proved reserves and related PV-10 as of December 31, 2019.

	Proved Reserves as of December 31, 2019[1]			
	California (San Joaquin and Ventura basins)	**Utah (Uinta basin)**	**Colorado (Piceance basin)**	**Total**
Proved developed reserves:				
Oil (MMBbl)	68	6	—	74
Natural Gas (Bcf)	—	30	9	39
NGLs (MMBbl)	—	1	—	1
Total (MMBoe)[2][3]	68	12	1	82
Proved undeveloped reserves:				
Oil (MMBbl)	54	2	—	56
Natural Gas (Bcf)	—	6	—	6
NGLs (MMBbl)	—	—	—	—
Total (MMBoe)[3]	54	3	—	57
Total proved reserves:				
Oil (MMBbl)	122	8	—	130
Natural Gas (Bcf)	—	36	9	45
NGLs (MMBbl)	—	1	—	1
Total (MMBoe)[3]	122	15	1	138
PV-10 (in billions)[4]	$ 1.7	$ 0.1	$ —	$ 1.8

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(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 $63.15 per Bbl Brent for oil and NGLs and $2.62 per MMBtu Henry Hub for natural gas at December 31, 2019. The volume-weighted average prices over the lives of the properties were $58.88 per Bbl of oil and condensate, $16.93 per Bbl of NGLs and $2.84 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) Approximately 18% of proved developed oil reserves, 0% of proved developed NGL reserves, 0% of proved developed natural gas reserves and 16% of total proved developed reserves 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, 2019, the average prices of Brent oil and Henry Hub natural gas were $64.16 per Bbl and $2.56 per Mcf, respectively, resulting in an oil-to-gas ratio of over 4 to 1 on an energy equivalent basis.

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

The following table provides a reconciliation of PV-10 of our proved reserves to the standardized measure of discounted future net cash flows at December 31, 2019:

	At December 31, 2019
	(in millions)
California PV-10	$ 1.7
Utah PV-10	0.1
Colorado PV-10	—
Total Company PV-10	1.8
Less: present value of future income taxes discounted at 10%	(0.3)
Standardized measure of discounted future net cash flows	$ 1.5

RESERVES AND PUD INVENTORY REPLACEMENT RATIOS AND F&D COSTS

The following table presents a calculation of our reserves and PUD inventory replacement ratio and F&D Cost from the total changes to our proved reserves in 2019, as well as the related costs incurred:

	Total Company	California
	(in MMBoe, except ratio and cost amounts)	
Extensions and discoveries (B)	13.3	13.3
Revisions of previous estimates[b]	(7.3)	11.2
Purchases of minerals	—	—
Organic changes (C)	6.0	24.5
Sales of minerals	—	—
Total reserves changes	6.0	24.5
Production	10.6	8.2
Reserve replacement ratio	57 %	299 %
Costs incurred (development costs)(A) ($ millions)	$ 280.0	
Finding & Development costs per Boe		
All-In (A)/(C)	$ 46.67	
Program (A)/(B)	$ 21.05	
Adjustments to All-In Finding & Development costs per BOE		
Costs incurred (development costs)(A) ($ millions)	$ 280.0	
Asset Retirement Obligations ($ millions)	(68.0)	
Adjusted Costs Incurred ($ millions) (D)	$ 212.0	
Total reserves changes	6.0	
Impairments (MMBoe)	13.5	
Adjusted organic changes (MMBoe) (E)	19.5	
Adjusted All-In Finding & Developing costs per BOE (D)/(E)	$ 10.87	

(a) All costs incurred in 2019 were development costs.

(b) Total Company revisions includes the removal of 16 MMBoe of proved undeveloped reserves (negative revision) in our Colorado Piceance natural gas properties, and the associated impairment.

	Total Company
Proved Undeveloped (PUD) drilling locations at Dec. 31, 2018	1,071
PUD locations drilled and revisions of previous inventory	(368)
PUD drilling location additions	586
PUD drilling locations at Dec. 31, 2019	1,289
PUD replacement ratio	159 %

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