UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2022

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to _________

Commission File Number 001-37419

PDC ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**95-2636730**
(State of incorporation)	(I.R.S. Employer Identification No.)

1775 Sherman Street, Suite 3000
Denver, Colorado 80203
(Address of principal executive offices) (Zip code)

Registrant's telephone number, including area code: (303) 860-5800

Securities registered pursuant to Section 12(b) of the Act.

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock, par value $0.01 per share	PDCE	Nasdaq Global Select Market

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See definitions of “large accelerated filer”, “accelerated filer”, “smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 92,144,663 shares of the Company's Common Stock ($0.01 par value) were outstanding as of October 25, 2022.

PDC ENERGY, INC.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") and the United States ("U.S.") Private Securities Litigation Reform Act of 1995 regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical fact included in and incorporated by reference into this report are "forward-looking statements". Words such as expect, anticipate, intend, plan, believe, seek, estimate, schedule and similar expressions or variations of such words are intended to identify forward-looking statements herein. Forward-looking statements include, among other things, statements regarding future production, costs and cash flows; impacts from the acquisition and integration of Great Western Petroleum, LLC ("Great Western"); drilling locations, zones and growth opportunities; impacts of Colorado political matters, including recent rulemaking initiatives influencing our ability to continue to obtain permits; our receipt of permits and the timing of such receipt; commodity prices and differentials; capital expenditures and projects, including the number of rigs employed; cash flows from operations relative to future capital investments; financial ratios and compliance with covenants in our revolving credit facility and other debt instruments; adequacy of midstream infrastructure; the return of capital to shareholders through buybacks of shares and/or payments of dividends; ongoing compliance with our legacy PDC consent decree and Great Western's compliance order on consent; risk of our counterparties' non-performance on derivative instruments; tax matters; and our ability to fund planned activities.

The above statements are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Forward-looking statements are always subject to risks and uncertainties, and become subject to greater levels of risk and uncertainty as they address matters further into the future. Throughout this report or accompanying materials, we may use the term "projection" or similar terms or expressions, or indicate that we have "modeled" certain future scenarios. We typically use these terms to indicate our current thoughts on possible outcomes relating to our business or our industry in periods beyond the current fiscal year. Because such statements relate to events or conditions further in the future, they are subject to increased levels of uncertainty.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- market and commodity price volatility, widening price differentials, and related impacts to the Company, including decreased revenue, income and cash flow, write-downs and impairments and decreased availability of capital;
- difficulties in integrating our operations as a result of any significant acquisitions, including the acquisition of Great Western, or acreage exchanges;
- adverse changes to our future cash flows, liquidity and financial condition;
- changes in, and interpretations and enforcement of, environmental and other laws and other political and regulatory developments, including in particular additional permit scrutiny in Colorado;
- the coronavirus 2019 ("COVID-19") pandemic, including its effects on commodity prices, downstream capacity, employee health and safety, business continuity and regulatory matters;
- declines in the value of our crude oil, natural gas and natural gas liquids ("NGLs") properties resulting in impairments;
- changes in, and inaccuracy of, reserve estimates and expected production and decline rates;
- timing and extent of our success in discovering, acquiring, developing and producing reserves;
- reductions in the borrowing base under our revolving credit facility;
- availability and cost of capital;
- risks inherent in the drilling and operation of crude oil and natural gas wells;
- timing and costs of wells and facilities;
- availability, cost, and timing of sufficient pipeline, gathering and transportation facilities and related infrastructure;
- limitations in the availability of supplies, materials, contractors and services that may delay the drilling or completion of our wells;
- potential losses of acreage or other impacts due to lease expirations, other title defects, or otherwise;
- risks inherent in marketing crude oil, natural gas and NGLs;
- effect of crude oil and natural gas derivative activities;

- impact of environmental events, governmental and other third-party responses to such events and our ability to insure adequately against such events;
- cost of pending or future litigation;
- impact to our operations, personnel retention, strategy, stock price and expenses caused by the actions of activist shareholders;
- uncertainties associated with future dividends to our shareholders or share buybacks;
- timing and amounts of federal and state income taxes;
- our ability to retain or attract senior management and key technical employees;
- an unanticipated assumption of liabilities or other problems with the Great Western acquisition or other acquisitions we may pursue;
- civil unrest, terrorist attacks and cyber threats;
- changes in general economic, business or industry conditions, including changes in interest rates and inflation rates and concerns regarding national or global recessionary conditions; and
- success of strategic plans, expectations and objectives for our future operations.

Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under *Item 1A, Risk Factors* made in our Annual Report on Form 10-K for the year ended December 31, 2021 (“2021 Form 10-K”) filed with the U.S. Securities and Exchange Commission (“SEC”) for further information on risks and uncertainties that could affect our business, financial condition, results of operations and prospects, which are incorporated by this reference as though fully set forth herein. We caution you not to place undue reliance on the forward-looking statements, which speak only as of the date of this report. **We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events. All forward-looking statements are qualified in their entirety by this cautionary statement.**

REFERENCES

Unless the context otherwise requires, references in this report to “PDC Energy”, “PDC”, “the Company”, “we”, “us”, “our” or “ours” refer to the registrant, PDC Energy, Inc. and all subsidiaries consolidated for the purposes of its financial statements.

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PDC ENERGY, INC.
Condensed Consolidated Balance Sheets
(in thousands, except share and per share data)
(Unaudited)

	September 30, 2022	December 31, 2021
Assets		
Current assets:		
Cash and cash equivalents	$ 45,649	$ 33,829
Accounts receivable, net	609,440	398,605
Fair value of derivatives	62,246	17,909
Prepaid expenses and other current assets	10,630	8,230
Total current assets	727,965	458,573
Properties and equipment, net	7,127,291	4,814,865
Fair value of derivatives	91,075	15,177
Other assets	81,759	48,051
Total Assets	$ 8,028,090	$ 5,336,666
Liabilities and Stockholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 213,473	$ 127,891
Production tax liability	247,946	99,583
Fair value of derivatives	389,234	304,870
Funds held for distribution	538,865	285,861
Accrued interest payable	19,511	10,482
Other accrued expenses	102,024	91,409
Total current liabilities	1,511,053	920,096
Long-term debt	1,393,528	942,084
Asset retirement obligations	152,709	127,526
Fair value of derivatives	100,860	95,561
Deferred income taxes	413,983	26,383
Other liabilities	474,610	314,769
Total liabilities	4,046,743	2,426,419
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 92,857,134 and 96,468,071 issued as of September 30, 2022 and December 31, 2021, respectively	929	965
Additional paid-in capital	2,950,625	3,161,941
Retained earnings (accumulated deficit)	1,037,229	(249,954)
Treasury shares - at cost, 130,091 and 54,960 as of September 30, 2022 and December 31, 2021, respectively	(7,436)	(2,705)
Total stockholders' equity	3,981,347	2,910,247
Total Liabilities and Stockholders' Equity	$ 8,028,090	$ 5,336,666

See accompanying Notes to Condensed Consolidated Financial Statements

PDC ENERGY, INC.
Condensed Consolidated Statements of Operations
(in thousands, except per share data)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Revenues				
Crude oil, natural gas and NGLs sales	$ 1,200,619	$ 703,136	$ 3,320,678	$ 1,704,396
Commodity price risk management gain (loss), net	306,749	(217,678)	(363,283)	(707,187)
Other income	3,921	904	8,833	4,058
Total revenues	1,511,289	486,362	2,966,228	1,001,267
Costs, expenses and other				
Lease operating expense	69,155	45,649	193,922	129,848
Production taxes	98,142	44,654	250,309	101,114
Transportation, gathering and processing expense	32,327	26,732	89,882	74,453
Exploration, geologic and geophysical expense	11,843	222	12,416	862
General and administrative expense	40,103	30,847	119,859	96,367
Depreciation, depletion and amortization	205,604	169,644	547,720	478,617
Accretion of asset retirement obligations	3,484	2,825	9,823	9,185
Impairment of properties and equipment	184	77	1,637	329
Loss (gain) on sale of properties and equipment	(86)	(220)	287	(561)
Other expense	—	303	—	2,496
Total costs, expenses and other	460,756	320,733	1,225,855	892,710
Income (loss) from operations	1,050,533	165,629	1,740,373	108,557
Interest expense, net	(18,629)	(20,098)	(49,139)	(59,199)
(Adjustment to) Gain on bargain purchase	(4,621)	—	95,652	—
Income (loss) before income taxes	1,027,283	145,531	1,786,886	49,358
Income tax benefit (expense)	(229,318)	(210)	(358,500)	(110)
Net income (loss)	$ 797,965	$ 145,321	$ 1,428,386	$ 49,248
Earnings (loss) per share:				
Basic	$ 8.40	$ 1.48	$ 14.87	$ 0.50
Diluted	$ 8.30	$ 1.45	$ 14.66	$ 0.49
Weighted average common shares outstanding:				
Basic	94,950	98,183	96,065	99,018
Diluted	96,122	99,966	97,467	100,534

See accompanying Notes to Condensed Consolidated Financial Statements

PDC ENERGY, INC.
Condensed Consolidated Statements of Cash Flows
(in thousands)
(Unaudited)

	Nine Months Ended September 30,	
	2022	2021
Cash flows from operating activities:		
Net income (loss)	$ 1,428,386	$ 49,248
Adjustments to net income (loss) to reconcile to net cash from operating activities:		
Net change in fair value of unsettled commodity derivatives	(349,798)	491,830
Depreciation, depletion and amortization	547,720	478,617
Impairment of properties and equipment	1,637	329
Exploratory dry hole costs	11,536	—
Accretion of asset retirement obligations	9,823	9,185
Non-cash stock-based compensation	19,952	17,294
Loss (gain) on sale of properties and equipment	287	(561)
Amortization of debt discount, premium and issuance costs	4,075	11,195
Deferred income taxes	357,500	—
Gain on bargain purchase	(95,652)	—
Other	(742)	2,353
Changes in assets and liabilities	150,067	(31,670)
Net cash from operating activities	2,084,791	1,027,820
Cash flows from investing activities:		
Capital expenditures for development of crude oil and natural gas properties	(773,748)	(428,831)
Capital expenditures for midstream assets	(8,747)	—
Capital expenditures for other properties and equipment	(8,619)	(363)
Cash paid for acquisition of an exploration and production business	(1,068,241)	—
Proceeds from sale of properties and equipment	640	4,720
Proceeds from divestitures	10,452	—
Net cash from investing activities	(1,848,263)	(424,474)
Cash flows from financing activities:		
Proceeds from revolving credit facility and other borrowings	2,049,200	502,800
Repayment of revolving credit facility and other borrowings	(1,599,200)	(670,800)
Repayment of convertible notes	—	(200,000)
Payment of debt issuance costs	(101)	—
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	(16,979)	(5,836)
Purchase of treasury shares under stock repurchase program	(556,035)	(107,318)
Dividends paid	(91,972)	(23,600)
Principal payments under financing lease obligations	(1,491)	(1,293)
Net cash from financing activities	(216,578)	(506,047)
Net change in cash and cash equivalents	19,950	97,299
Cash, cash equivalents and restricted cash, beginning of period	33,829	2,623
Cash, cash equivalents and restricted cash, end of period	$ 53,779	$ 99,922

See accompanying Notes to Condensed Consolidated Financial Statements

PDC ENERGY, INC.
Condensed Consolidated Statements of Stockholders' Equity
(in thousands, except dividends per share)
(Unaudited)

	Nine Months Ended September 30, 2022						
	Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount		
Balance, January 1, 2022	96,468	$ 965	$ 3,161,941	(55)	$ (2,705)	$ (249,954)	$ 2,910,247
Net income (loss)	—	—	—	—	—	(31,960)	(31,960)
Stock-based compensation	655	7	1,798	—	3,669	—	5,474
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(164)	(9,203)	—	(9,203)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(53)	(2)	(3,022)	53	3,024	—	—
Retirement of treasury shares	(1,320)	(13)	(83,508)	1,320	83,521	—	—
Issuance of treasury shares	—	—	—	67	—	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(1,326)	(85,339)	—	(85,339)
Dividends declared ($0.25 per share)	—	—	(24,468)	—	—	—	(24,468)
Balance, March 31, 2022	95,750	957	3,052,741	(105)	(7,033)	(281,914)	2,764,751
Net income (loss)	—	—	—	—	—	662,381	662,381
Issuance of stock pursuant to acquisition	4,007	40	293,274	—	—	—	293,314
Stock-based compensation	337	3	6,924	—	369	—	7,296
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(101)	(7,657)	—	(7,657)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(101)	(1)	(7,635)	101	7,636	—	—
Retirement of treasury shares	(2,946)	(29)	(214,123)	2,946	214,152	—	—
Issuance of treasury shares	—	—	—	5	—	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(2,966)	(214,706)	—	(214,706)
Dividends declared ($0.35 per share)	—	—	(34,658)	—	—	—	(34,658)
Balance, June 30, 2022	97,047	970	3,096,523	(120)	(7,239)	380,467	3,470,721
Net income	—	—	—	—	—	797,965	797,965
Stock-based compensation	7	—	7,254	—	(72)	—	7,182
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(2)	(119)	—	(119)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(2)	—	(69)	2	115	(46)	—
Retirement of treasury shares	(4,195)	(41)	(153,083)	4,195	261,030	(107,906)	—
Issuance of treasury shares	—	—	—	—	—	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(4,205)	(261,151)	—	(261,151)
Dividends declared ($0.35 per share)	—	—	—	—	—	(33,251)	(33,251)
Balance, September 30, 2022	92,857	$ 929	$ 2,950,625	(130)	$ (7,436)	$ 1,037,229	$ 3,981,347

See accompanying Notes to Condensed Consolidated Financial Statements

	Nine Months Ended September 30, 2021						
	Common Stock		Additional Paid-in Capital	Treasury Stock		Accumulated Deficit	Total Stockholders' Equity
	Shares	Amount		Shares	Amount		
Balance, January 1, 2021	99,759	$ 998	$ 3,387,754	(38)	$ (949)	$ (772,265)	$ 2,615,538
Net income (loss)	—	—	—	—	—	(9,036)	(9,036)
Issuance pursuant to acquisition	—	—	—	—	—	—	—
Stock-based compensation	209	2	3,670	—	1,348	—	5,020
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(81)	(2,356)	—	(2,356)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(33)	—	(1,091)	33	1,091	—	—
Retirement of treasury shares	(568)	(6)	(21,061)	568	21,067	—	—
Issuance of treasury shares	—	—	—	65	—	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(598)	(22,098)	—	(22,098)
Balance, March 31, 2021	99,367	994	3,369,272	(51)	(1,897)	(781,301)	2,587,068
Net income (loss)	—	—	—	—	—	(87,037)	(87,037)
Stock-based compensation	295	3	5,742	—	750	—	6,495
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(92)	(3,300)	—	(3,300)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(78)	(1)	(2,807)	78	2,808	—	—
Retirement of treasury shares	(677)	(7)	(26,922)	684	27,235	—	306
Issuance of treasury shares	—	—	—	22	—		—
Purchase of treasury shares under stock repurchase program	—	—	—	(661)	(26,509)	—	(26,509)
Dividends declared ($0.12 per share)	—	—	(12,117)	—	—	—	(12,117)
Balance, June 30, 2021	98,907	989	3,333,168	(20)	(913)	(868,338)	2,464,906
Net income (loss)	—	—	—	—	—	145,321	145,321
Stock-based compensation	12	—	5,730	—	49	—	5,779
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(4)	(180)	—	(180)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(2)	—	(91)	2	91	—	—
Retirement of treasury shares	(1,476)	(15)	(59,610)	1,476	59,625	—	—
Issuance of treasury shares	—	—	—	1	—	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(1,476)	(59,666)	—	(59,666)
Retirement of treasury shares	(1,476)	(15)	(59,610)	1,476	59,625	—	—
Dividends declared ($0.12 per share)	—	—	(11,936)	—	—	—	(11,936)
Balance, September 30, 2021	97,441	$ 974	$ 3,267,261	(21)	$ (994)	$ (723,017)	$ 2,544,224

See accompanying Notes to Condensed Consolidated Financial Statements

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. is a domestic independent exploration and production company that acquires, explores and develops properties for the production of crude oil, natural gas and NGLs, with operations in the Wattenberg Field in Colorado and the Delaware Basin in west Texas. Our operations in the Wattenberg Field are focused in the horizontal Niobrara and Codell plays and our Delaware Basin operations are primarily focused in the horizontal Wolfcamp zones. As of September 30, 2022, we owned an interest in approximately 4,200 gross productive wells.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC and our wholly-owned subsidiaries. All material intercompany accounts and transactions have been eliminated in consolidation. In our opinion, the accompanying condensed consolidated financial statements contain all adjustments, consisting of normal recurring adjustments necessary for a fair statement of the results of interim periods presented in accordance with accounting principles generally accepted in the United States of America (“U.S. GAAP”) and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. The December 31, 2021 condensed consolidated balance sheet data was derived from audited statements, but does not include all disclosures required by U.S. GAAP. The information presented in this Quarterly Report on Form 10-Q should be read in conjunction with our audited consolidated financial statements and notes thereto included in our 2021 Form 10-K. Our results of operations and cash flows for the nine months ended September 30, 2022 are not necessarily indicative of the results to be expected for the full year or any other future period.

NOTE 2 - BUSINESS COMBINATION

On May 6, 2022, we completed the acquisition of Great Western Petroleum, LLC (“Great Western”), for approximately $1.4 billion, inclusive of Great Western’s net debt (the “Great Western Acquisition”). Great Western was an independent oil and gas company focused on the exploration, production and development of crude oil and natural gas in the Wattenberg Field of Colorado. The consideration paid was $542.5 million in cash and approximately 4.0 million shares of our common stock, valued at $293.3 million on the acquisition date. In addition, we paid off the Great Western secured credit facility totaling $235.8 million and irrevocably deposited $361.2 million on Great Western’s behalf to pay and discharge on May 20, 2022 Great Western’s 12 percent senior secured notes due 2025, inclusive of unpaid accrued interest and a premium for early termination. The cash portion of the purchase price and the termination of Great Western’s debt were funded through a combination of cash on hand and availability under our revolving credit facility.

Purchase Price Allocation

The Great Western Acquisition has been accounted for using the acquisition method under Accounting Standards Codification (“ASC”) 805, *Business Combinations*, with PDC being treated as the accounting acquirer. Accordingly, we conducted assessments of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values, while transaction and integration costs associated with the acquisition were expensed as incurred.

The following table presents our preliminary allocation of the total purchase price of Great Western to the identifiable assets acquired and liabilities assumed based on the fair values as of the acquisition date:

		(in thousands, except share and per share data)
Consideration:		
Cash	$	542,500
Retirement of Great Western's credit facility		235,822
Extinguishment of Great Western's secured senior notes		361,231
Total cash consideration	$	1,139,553
Common stock issued		4,007,018
Fair value of PDC common stock on May 6, 2022	$	73.20
Total fair value of common stock issued		293,314
Total consideration	$	1,432,867
Assets acquired:		
Cash	$	63,183
Accounts receivable		164,026
Other current assets		3,129
Properties and equipment, net - proved		2,089,443
Properties and equipment, net - other		7,035
Other noncurrent assets		21,888
Total assets acquired	$	2,348,704
Liabilities assumed:		
Accounts payable	$	(118,485)
Production tax liability		(110,940)
Funds held for distribution		(166,212)
Other current liabilities		(18,603)
Fair value of derivatives		(319,600)
Asset retirement obligations		(23,442)
Deferred tax liabilities		(30,100)
Other liabilities		(32,803)
Total liabilities assumed	$	(820,185)
Total identifiable net assets acquired	$	1,528,519
Gain on bargain purchase		95,652
Purchase price consideration	$	1,432,867

Determining the fair values of the assets and liabilities of Great Western requires judgement and certain assumptions to be made, the most significant of these being related to the valuation of crude oil and natural gas properties. The majority of the measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market, and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs and assumptions to the valuation of proved and unproved crude oil and natural gas properties include estimates of reserve volumes, future operating and development costs, future commodity prices, lease terms and expirations and a market-based weighted-average cost of capital rate of 14.25 percent. These inputs require significant judgments and estimates by management at the time of the valuation. Due to this, the final purchase price allocation is considered an ongoing process and the measurement period will extend into the fourth quarter of 2022. Through September 30, 2022, there have been immaterial adjustments made to the allocation presented in the Quarterly Report on Form 10-Q for the quarter ended June 30, 2022 filed with the SEC on August 3, 2022.

ASC 805, *Business Combinations*, requires that any excess of purchase price over the fair value of assets acquired, including identifiable intangibles and liabilities assumed, be recognized as goodwill and any excess of fair value of acquired net assets, including identifiable intangible assets over the acquisition consideration, results in a gain from bargain purchase. Prior to recording a gain, the acquiring entity must reassess whether all assets acquired and assumed liabilities have been identified and recognized and perform re-measurements to verify that the consideration paid, assets acquired and liabilities assumed have been properly valued. The Great Western Acquisition resulted in a gain on bargain purchase due to the estimated fair value of the identifiable net assets acquired exceeding the purchase consideration transferred by $95.7 million and is shown as a gain on bargain purchase on our condensed consolidated statement of operations, net of related income taxes of $30.1 million. Upon completion of our assessment, we concluded that recording a gain on bargain purchase was appropriate and required under ASC 805. The bargain purchase was primarily attributable to the increase in commodity price forecasts from the date we entered into the definitive purchase agreement with Great Western, February 26, 2022, to the closing date of the acquisition, May 6, 2022, when the fair value of crude oil and natural gas reserves acquired were determined. Additionally, the majority of the acquisition consideration was fixed and therefore did not fluctuate as a result of market increases or decreases between the date of entry into the agreement through the closing date.

The results of operations for the Great Western Acquisition since the closing date have been included on our condensed consolidated financial statements for the three and nine months ended September 30, 2022 and include approximately $266.1 million and $458.9 million of total revenues, respectively, and $162.2 million and $293.3 million of income from operations, respectively. During the three and nine months ended September 30, 2022, we recognized total transaction costs of $1.2 million and $11.7 million, respectively, which are included in general and administrative expense on the condensed consolidated statement of operations.

Pro Forma Information. The following unaudited pro forma financial information represents a summary of the condensed consolidated results of operations for the three months ended September 30, 2021 and nine months ended September 30, 2022 and 2021, assuming the acquisition had been completed as of January 1, 2021. The financial information for the three months ended September 30, 2022 was included on our condensed consolidated financial statements and therefore does not require a pro forma disclosure. The pro forma financial information is not necessarily indicative of the results of operations that would have been achieved if the acquisition had been effective as of these dates, or of future results.

The information below reflects certain nonrecurring pro forma adjustments that were directly related to the business combination based on available information and certain assumptions that we believe are reasonable, including (i) our common stock issued to the owners of Great Western, (ii) the increase in depletion reflecting the relative fair values and production volumes attributable to Great Western's properties and the revision to the depletion rate reflecting the reserve volumes acquired, (iii) adjustments to interest expense as a result of payoff of Great Western's credit facility and secured senior notes, (iv) the adjustment to reflect the gain on bargain purchase, and (v) the estimated tax impacts of the pro forma adjustments. In addition, pro forma earnings were adjusted to exclude acquisition-related costs incurred by us and Great Western totaling approximately $4.9 million and $33.4 million for the three and nine months ended September 30, 2022, respectively, and included the total costs of $33.4 million for the nine months ended September 30, 2021.

	Three months ended September 30,	Nine months ended September 30,	
	2021	2022	2021
	(in thousands, except per share data)		
Total revenues	$ 570,736	$ 3,017,856	$ 1,189,724
Net income (loss)	128,818	1,299,632	(8,654)
Earnings (loss) per share:			
Basic	$ 1.26	$ 12.99	$ (0.08)
Diluted	1.24	12.81	(0.08)

NOTE 3 - REVENUE RECOGNITION

Disaggregated Revenue. The following table presents crude oil, natural gas and NGLs sales disaggregated by commodity and operating region for the periods presented:

Revenue by Commodity and Operating Region	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Three Months Percent Change	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021	Nine Months Percent Change
	(in thousands)					
Crude oil						
Wattenberg Field	$ 577,451	$ 341,822	69 %	$ 1,628,524	$ 869,336	87 %
Delaware Basin	103,263	80,751	28 %	342,772	177,587	93 %
Total	$ 680,714	$ 422,573	61 %	1,971,296	1,046,923	88 %
Natural gas						
Wattenberg Field	$ 277,098	$ 116,263	138 %	658,510	287,949	129 %
Delaware Basin	42,084	19,207	119 %	101,514	38,970	160 %
Total	$ 319,182	$ 135,470	136 %	760,024	326,919	132 %
NGLs						
Wattenberg Field	$ 170,667	$ 121,837	40 %	491,094	283,119	73 %
Delaware Basin	30,056	23,256	29 %	98,264	47,435	107 %
Total	$ 200,723	$ 145,093	38 %	589,358	330,554	78 %
Crude oil, natural gas and NGLs						
Wattenberg Field	$ 1,025,216	$ 579,922	77 %	2,778,128	1,440,404	93 %
Delaware Basin	175,403	123,214	42 %	542,550	263,992	106 %
Total	$ 1,200,619	$ 703,136	71 %	$ 3,320,678	$ 1,704,396	95 %

NOTE 4 - FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

Derivative Financial Instruments. We measure the fair value of our commodity derivative instruments based upon a pricing model that utilizes market-based inputs, including, but not limited to, the contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates, volatility factors and nonperformance risk. Nonperformance risk considers the effect of our credit standing on the fair value of derivative liabilities and the effect of our counterparties' credit standings on the fair value of derivative assets. Both inputs to the model are based on published credit default exchange rates and the duration of each outstanding derivative position. We use our counterparties' valuations to assess reasonableness of our fair value measurement.

Our crude oil and natural gas fixed-price exchanges and basis exchanges are included in Level 2. Our collars are included in Level 3. The following table presents, for each applicable level within the fair value hierarchy, our derivative assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis as of the dates indicated:

		September 30, 2022			December 31, 2021		
	Condensed Consolidated Balance Sheet Line Item	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)					
Derivative assets							
Current	Fair value of derivatives	$ 35,577	$ 26,669	$ 62,246	$ —	$ 17,909	$ 17,909
Non-current	Fair value of derivatives	72,161	18,914	91,075	605	14,572	15,177
Total		$ 107,738	$ 45,583	$ 153,321	$ 605	$ 32,481	$ 33,086
Derivative liabilities							
Current	Fair value of derivatives	$ (291,427)	$ (97,807)	$ (389,234)	$ (230,695)	$ (74,175)	$ (304,870)
Non-current	Fair value of derivatives	(80,596)	(20,264)	(100,860)	(74,715)	(20,846)	(95,561)
Total		$ (372,023)	$ (118,071)	$ (490,094)	$ (305,410)	$ (95,021)	$ (400,431)

The following table presents a reconciliation of our Level 3 assets and liabilities measured at fair value for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in thousands)			
Fair value of Level 3 instruments, net asset (liability) beginning of period	$ (205,520)	$ (117,985)	$ (62,540)	$ (8,427)
Changes in fair value included on condensed consolidated statements of operations line item:				
Commodity price risk management gain (loss), net	61,565	(87,036)	(211,363)	(214,556)
Settlements included on condensed consolidated statement of operations line items:				
Commodity price risk management gain (loss), net	71,467	46,368	201,415	64,330
Fair value of Level 3 instruments, net asset (liability) end of period	$ (72,488)	$ (158,653)	$ (72,488)	$ (158,653)
Net change in fair value of Level 3 unsettled derivatives included on condensed consolidated statements of operations line item:				
Commodity price risk management gain (loss), net	$ 67,566	$ (78,786)	$ (54,500)	$ (210,430)

The significant unobservable input used in the fair value measurement of our derivative contracts is the implied volatility curve. A significant increase or decrease in the implied volatility, in isolation, would have a directionally similar effect resulting in a significantly higher or lower fair value measurement of our Level 3 derivative contracts. There has been no change in the methodology we apply to measure the fair value of our Level 3 derivative contracts during the periods covered by the financial statements.

Nonrecurring Fair Value Measurements

Acquisitions and Impairment of Long-lived Assets. We measure fair value using inputs that are not observable in the market, and are therefore designated as Level 3 within the valuation hierarchy, on a nonrecurring basis for any acquired assets or businesses and to review our proved and unproved crude oil and natural gas properties for possible impairment.

Asset Retirement Obligations. We measure the fair value of asset retirement obligations as of the date a well begins drilling or when production equipment and facilities are installed using a discounted cash flow model based on inputs that are not observable in the market and therefore are designated as Level 3 within the valuation hierarchy.

Other Financial Instruments

The carrying value of the financial instruments included in current assets and current liabilities approximates fair value due to the short-term maturities of these instruments.

Long-term Debt. The portion of our long-term debt related to our revolving credit facility approximates fair value, as the applicable interest rates are variable and reflective of market rates. We have elected not to account for the portion of our debt related to our senior notes under the fair value option; however, we have determined an estimate of the fair values based on measurements of trading activity and broker or dealer quotes, which are published market prices, and therefore are Level 2 inputs. The table below presents these estimates of the fair value of the portion of our long-term debt related to our senior notes as of the dates indicated:

		September 30, 2022		December 31, 2021	
	Nominal Interest	Estimated Fair Value	Percent of Par	Estimated Fair Value	Percent of Par
		(in millions)		*(in millions)*	
Senior Notes:					
2024 Senior Notes	6.125 %	$ 198.6	99.3 %	$ 202.8	101.4 %
2026 Senior Notes	5.75 %	694.5	92.6 %	775.5	103.4 %

NOTE 5 - COMMODITY DERIVATIVE FINANCIAL INSTRUMENTS

Objective and Strategy. Our results of operations and operating cash flows are affected by changes in market prices for crude oil, natural gas and NGLs. To manage a portion of our exposure to price volatility from producing crude oil and natural gas we enter into commodity derivative contracts such as collars, fixed-price exchanges and basis protection exchanges, to protect against price declines in future periods. We do not enter into derivative contracts for speculative or trading purposes.

We believe our commodity derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. Depending on changes in crude oil and natural gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our derivative positions from current levels. As of September 30, 2022, we had derivative instruments in place for a portion of our anticipated production in 2022 through 2025. Our commodity derivative contracts have been entered into at no upfront cost to us as we hedge our anticipated production at the then-prevailing commodity market prices, without adjustment for premium or discount.

Effect of Derivative Instruments on the Condensed Consolidated Statements of Operations. The following table presents the impact of our derivative instruments on our condensed consolidated statements of operations for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Condensed Consolidated Statement of Operations Line Item	**2022**	**2021**	**2022**	**2021**
		(in thousands)		
Commodity price risk management gain (loss), net				
Net settlements	$ (252,826)	$ (129,571)	$ (713,081)	$ (215,357)
Net change in fair value of unsettled derivatives	559,575	(88,107)	349,798	(491,830)
Total commodity price risk management gain (loss), net	$ 306,749	$ (217,678)	$ (363,283)	$ (707,187)

Commodity Derivative Contracts. As of September 30, 2022, we had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is presented:

	Collars			Fixed-Price Swaps		
Commodity/ Index/ Maturity Period	**Quantity** *(Crude oil - MBbls Natural Gas - BBtu)*	**Weighted Average Contract Price** **Floors**	**Ceilings**	**Quantity** *(Crude Oil - MBbls Gas and Basis-BBtu)*	**Weighted Average Contract Price**	**Fair Value September 30, 2022** *(in thousands)*
Crude Oil						
NYMEX						
2022	1,368	$ 53.18	$ 67.33	3,426	$ 58.35	$ (86,281)
2023	5,937	61.27	83.11	9,804	66.42	(63,132)
2024	825	65.91	89.58	6,126	70.59	27,532
2025	—	—	—	2,640	75.10	26,996
Total Crude Oil	8,130			21,996		(94,885)
Natural Gas						
NYMEX						
2022	10,357	3.14	4.68	14,996	2.95	(84,559)
2023	17,227	3.17	4.86	41,825	3.05	(125,299)
2024	—	—	—	26,160	3.54	(28,450)
2025	—	—	—	6,225	4.87	1,608
	27,584			89,206		(236,700)
CIG						
2023	—	—	—	8,760	3.39	(14,470)
2025	—	—	—	4,800	3.10	(4,711)
	—			13,560		(19,181)
Total Natural Gas	27,584			102,766		(255,881)
Basis Protection - Natural Gas						
CIG						
2022				25,215	(0.27)	15,258
2023				57,782	(0.29)	309
2024				26,160	(0.39)	(1,350)
2025				6,225	(0.37)	(224)
Total Basis Protection - Natural Gas				115,382		13,993
Commodity Derivatives Fair Value						$ (336,773)

Effect of Derivative Instruments on the Condensed Consolidated Balance Sheet. The balance sheet line items and fair value amounts of our derivative instruments are disclosed in *Note 4 - Fair Value Measurements.*

Our financial derivative agreements contain master netting provisions that provide for the net settlement of contracts through a single payment in the event of early termination. We have elected not to offset the fair value positions recorded on our condensed consolidated balance sheets.

The following table reflects the impact of netting agreements on gross derivative assets and liabilities as of September 30, 2022:

	Total Gross Amount Presented on the Balance Sheet	Effect of Master Netting Agreements	Total Net Amount
		(in thousands)	
Derivative assets:			
Derivative instruments, at fair value	$ 153,321	$ (144,133)	$ 9,188
Derivative liabilities:			
Derivative instruments, at fair value	$ 490,094	$ (144,133)	$ 345,961

Derivative Counterparties. Our commodity derivative instruments expose us to the risk of non-performance by our counterparties. We use financial institutions who are also lenders under our revolving credit facility as counterparties to our commodity derivative contracts. To date, we have had no derivative counterparty default losses. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the potential impact of nonperformance of our current counterparties on the fair value of our derivative instruments is not significant at September 30, 2022; however, this determination may change.

NOTE 6 - PROPERTIES AND EQUIPMENT, NET

The following table presents the components of properties and equipment, net of accumulated depreciation, depletion and amortization ("DD&A") as of the dates indicated:

	September 30, 2022	December 31, 2021
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$ 10,961,408	$ 8,310,018
Unproved	257,919	306,181
Total crude oil and natural gas properties	11,219,327	8,616,199
Equipment and other	69,570	63,099
Land and buildings	25,406	19,928
Construction in progress	614,313	371,968
Properties and equipment, at cost	11,928,616	9,071,194
Accumulated DD&A	(4,801,325)	(4,256,329)
Properties and equipment, net	$ 7,127,291	$ 4,814,865

Suspended Well Costs. The following table presents the capitalized exploratory well cost pending determination of proved reserves and included in properties and equipment for the periods presented:

	Year Ended December 31, 2021
	(in thousands, except for number of wells)
Beginning balance	$ 7,459
Additions to capitalized exploratory well costs pending the determination of proved reserves	5,902
Reclassifications to proved properties	(13,361)
Ending balance	$ —
Number of wells pending determination at period-end	—

As of September 30, 2022, there were no capitalized exploratory well costs.

Exploratory Dry Hole. During the nine months ended September 30, 2022, we drilled and turned-in-line an exploratory well in the Delaware Basin that did not yield sufficient projected returns for it to be deemed economically viable. Therefore, during the third quarter of 2022, we expensed the associated lease costs and related infrastructure assets of the exploratory dry hole at a cost of $11.5 million, an amount which was recognized on the condensed consolidated statements of operations as exploration, geologic and geophysical expense.

NOTE 7 - ACCOUNTS RECEIVABLE, OTHER ACCRUED EXPENSES AND OTHER LIABILITIES

Accounts Receivable. The following table presents the components of accounts receivable, net of allowance for doubtful accounts, as of the dates indicated:

	September 30, 2022	December 31, 2021
	(in thousands)	
Crude oil, natural gas and NGLs sales	$ 555,931	$ 368,991
Joint interest billings	45,087	24,860
Other	13,924	10,809
Allowance for doubtful accounts	(5,502)	(6,055)
Accounts receivable, net	$ 609,440	$ 398,605

Other Accrued Expenses. The following table presents the components of other accrued expenses as of the dates indicated:

	September 30, 2022	December 31, 2021
	(in thousands)	
Employee benefits	$ 25,945	$ 29,319
Asset retirement obligations	24,276	32,146
Environmental expenses	27,387	11,942
Operating and finance leases	6,211	7,197
Other	18,205	10,805
Other accrued expenses	$ 102,024	$ 91,409

Other Liabilities. The following table presents the components of other liabilities as of the dates indicated:

	September 30, 2022	December 31, 2021
	(in thousands)	
Deferred midstream gathering credits	$ 150,468	$ 159,788
Production taxes	253,481	131,865
Operating and finance leases	41,870	6,274
Other	28,791	16,842
Other liabilities	$ 474,610	$ 314,769

Deferred Midstream Gathering Credits. In 2019, we entered into agreements pursuant to which we dedicated the gathering of certain of our production and all water gathering and disposal volumes in the Delaware Basin. The terms of these agreements range from 15 to 22 years. The acreage dedication agreements resulted in initial cash receipts and are being amortized on a units-of-production basis. The amortization rates are assessed on an annual basis for changes in estimated future production.

The following table presents the amortization charges related to our deferred credits recognized on the condensed consolidated statements of operations for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in thousands)			
Transportation, gathering and processing expense	$ 3,361	$ 2,014	$ 7,691	$ 5,343
Lease operating expense	815	732	2,281	1,817

NOTE 8 - LONG-TERM DEBT

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $6.5 million and $7.9 million as of September 30, 2022 and December 31, 2021, respectively, consists of the following:

	September 30, 2022	December 31, 2021
	(in thousands)	
Revolving credit facility due November 2026	$ 450,000	$ —
6.125% Senior Notes due September 2024	199,041	198,674
5.75% Senior Notes due May 2026	744,487	743,410
Total debt, net of unamortized discount, premium and debt issuance costs	$ 1,393,528	$ 942,084

Revolving Credit Facility

In November 2021, we entered into a Fifth Amended and Restated Credit Agreement (the “Restated Credit Agreement”), which provides for a maximum credit amount of $2.5 billion, subject to certain limitations, an initial borrowing base of $2.4 billion and an elected commitment of $1.5 billion. The Restated Credit Agreement matures on the earlier to occur of (i) the end of the five-year term on November 2, 2026 or (ii) the date that is 91 days prior to the scheduled maturity of the 2026 Senior Notes if the aggregate outstanding principal amount of those notes exceeds $500 million and our commitment utilization exceeds 50%.

The revolving credit facility is available for working capital requirements, capital investments, acquisitions, to support letters of credit and for general business purposes. The borrowing base is based on, among other things, the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests. The borrowing base is subject to a semi-annual redetermination on November 1 and May 1 based upon quantification of our reserves at June 30 and December 31, and is also subject to a redetermination upon the occurrence of certain events. Substantially all of our crude oil and natural gas properties have been mortgaged or pledged as security for our revolving credit facility. The Restated Credit Agreement includes an investment grade period election pursuant to which we have an option to remove our borrowing base limitations and terminate the liens securing the Restated Credit Agreement when certain debt ratings are achieved.

As of September 30, 2022, we had a borrowing base of $3.0 billion, an elected commitment of $1.5 billion and availability under our revolving credit facility of $1,029.6 million, net of $20.4 million of letters of credit outstanding. In October 2022, as part of our credit facility 2022 semi-annual redetermination, our borrowing base increased from $3.0 billion to $3.5 billion as a result of the reserves acquired from the Great Western Acquisition; however, we maintained our elected commitment amount of $1.5 billion.

The outstanding principal amount under the revolving credit facility accrues interest at a varying interest rate that fluctuates with an alternate base rate (equal to the greatest of the administrative agent's prime rate, the federal funds rate plus a premium and the rate for dollar deposits in the Secured Overnight Financing Rate ("SOFR") for one month, plus a premium) or, at our election, a rate equal to SOFR for certain time periods. Additionally, commitment fees, interest margin and other bank fees, charged as a component of interest, vary with our utilization of the facility. As of September 30, 2022, the applicable interest margin is 1.0 percent for the alternate base rate option or 2.0 percent for the SOFR option, and the unused commitment fee is 0.375 percent. Principal payments are generally not required until the maturity date of the revolving credit facility, unless the borrowing base falls below the outstanding balance. The Restated Credit Agreement also includes the ability to add certain sustainability-linked key performance indicators to be agreed upon between us, the administrative agent and a majority of the lenders and that may impact the applicable margin and commitment fee rate.

The revolving credit facility contains various restrictive covenants and compliance requirements, which include, among other things: (i) maintenance of certain financial ratios, as defined per the revolving credit facility, including a minimum current ratio of 1.0:1.0 and a maximum leverage ratio of 3.5:1.0; (ii) restrictions on the payment of cash dividends; (iii) limits on the incurrence of additional indebtedness; (iv) prohibition on the entry into commodity hedges exceeding a specified percentage of our expected production; and (v) restrictions on mergers and dispositions of assets. As of September 30, 2022, we were in compliance with all covenants related to our revolving credit facility.

As of September 30, 2022 and December 31, 2021, debt issuance costs related to our revolving credit facility were $14.4 million and $16.9 million, respectively, and are included in other assets on our condensed consolidated balance sheets.

Senior Notes

The following table summarizes the face values, interest rates, maturity dates, semi-annual interest payment dates, and optional redemption periods related to our outstanding senior note obligations as of September 30, 2022:

	2024 Senior Notes	2026 Senior Notes
Outstanding principal amounts (in thousands)	$ 200,000	$ 750,000
Interest rate	6.125 %	5.75 %
Maturity date	September 15, 2024	May 15, 2026
Interest payment dates	March 15, September 15	May 15, November 15
Redemption periods [1]	September 15, 2022	May 15, 2024

(1) At any time prior to the indicated dates, we have the option to redeem all or a portion of our senior notes of the applicable series at the redemption amounts specified in the respective senior note indenture plus accrued and unpaid interest to the date of redemption. On or after the indicated dates, we may redeem all or a portion of the senior notes at a redemption amount equal to 100% of the principal amount of the senior notes being redeemed plus accrued and unpaid interest to the date of redemption.

The Senior Notes are senior unsecured obligations and rank senior in right of payment to our future indebtedness that is expressly subordinated to the notes; equal in right of payment to our existing and future indebtedness that is not so subordinated; effectively junior in right of payment to all of our secured indebtedness to the extent of the value of the assets securing such indebtedness; and structurally junior to all existing and future indebtedness (including trade payables) incurred by our non-guarantor subsidiaries.

Upon the occurrence of a "change of control", as defined in the indentures for the Senior Notes, holders will have the right to require us to repurchase all or a portion of the notes at a price equal to 101 percent of the aggregate principal amount of the notes repurchased, together with accrued and unpaid interest to the date of purchase. In connection with certain asset sales, we may, under certain circumstances, be required to use the net cash proceeds of such asset sale to make an offer to purchase the notes at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase.

The indentures governing the Senior Notes contain covenants and restricted payment provisions that, among other things, limit our ability and the ability of our subsidiaries to incur additional indebtedness; pay dividends or make distributions on our stock; purchase or redeem stock or subordinated indebtedness; make investments; create certain liens; enter into agreements that restrict distributions or other payments by restricted subsidiaries to us; enter into transactions with affiliates; sell assets; consolidate or merge with or into other companies or transfer all or substantially of our assets; and create unrestricted subsidiaries. As of September 30, 2022, we were in compliance with all covenants and all restricted payment provisions related to our Senior Notes.

Our wholly-owned subsidiaries, PDC Permian, Inc. and Pioneer Water Pipeline LLC (acquired in connection with the Great Western Acquisition), are each a guarantor of our obligations under the 2024 Senior Notes and the 2026 Senior Notes (collectively, the "Senior Notes") and our credit facility.

NOTE 9 - LEASES

We have operating leases for office space and well equipment, and finance leases for vehicles. Our leases have remaining lease terms ranging from one to eleven years. We had short-term lease costs of $75.0 million and $48.2 million for the three months ended September 30, 2022 and September 30, 2021, respectively, and $230.5 million and $158.4 million for the nine months ended September 30, 2022 and September 30, 2021, respectively. Our short-term lease costs include amounts that are capitalized as part of the cost of assets and are recorded as properties and equipment, or recognized as expense.

The following table presents the balance sheet classification of our leases as of the dates indicated:

Leases	**Condensed Consolidated Balance Sheet Line Item**	**September 30, 2022**	**December 31, 2021**
		(in thousands)	
Operating lease right-of-use assets	Other assets	$ 21,662	$ 7,630
Finance lease right-of-use assets	Properties and equipment, net	6,018	3,483
Total right-of-use assets		$ 27,680	$ 11,113
Operating lease obligation - current	Other accrued expenses	4,174	5,937
Operating lease obligation - non-current	Other liabilities	37,831	4,044
Finance lease obligation - current	Other accrued expenses	2,037	1,260
Finance lease obligation - non-current	Other liabilities	4,039	2,230
Total lease liabilities		$ 48,081	$ 13,471
Weighted average remaining lease term (years)		7.7	2.8
Weighted average discount rate		5.0 %	4.8 %

In September 2022, we entered into a three-year drilling rig agreement with gross total lease payments of approximately $34.0 million which we expect to commence and be recognized on our balance sheet in the first quarter of 2023.

NOTE 10 - ASSET RETIREMENT OBLIGATIONS

The following table presents the changes in carrying amounts of the asset retirement obligations associated with our working interests in crude oil and natural gas properties for the nine months ended September 30, 2022:

	(in thousands)
Asset retirement obligations at beginning of period	$ 159,672
Obligations incurred with development activities and other	3,654
Obligations incurred with acquisition	23,442
Accretion expense	9,823
Revisions in estimated cash flows	(284)
Obligations discharged with asset retirements and divestitures	(19,322)
Asset retirement obligations at end of period	176,985
Current portion [(1)]	(24,276)
Long-term portion	$ 152,709

(1) The current portion of the asset retirement obligation is included in other accrued expenses on our condensed consolidated balance sheets.

Our estimated asset retirement obligations liability is based on historical experience in plugging and abandoning wells, estimated economic lives and estimated plugging, abandonment and surface reclamation costs considering federal and state regulatory requirements in effect at the time that the obligation is incurred. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations liability, a corresponding adjustment is made to the properties and equipment balance. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and as accretion expense.

NOTE 11 - COMMITMENTS AND CONTINGENCIES

Commitments. We routinely enter into, extend or amend operating agreements in the ordinary course of business. We have long-term transportation, sales, processing and facility expansion agreements for pipeline capacity and water delivery and disposal commitments. There were no significant commitments entered into during the nine months ended September 30, 2022, other than the commitments assumed as a result of the Great Western Acquisition including an aggregate of approximately $393.3 million in various sales, transportation, gathering and processing contractual obligations. For details of our existing commitments excluding the Great Western Acquisition, refer to *Note 13 - Commitments and Contingencies* in *Item 8. Financial Statements and Supplementary Data* included in our 2021 Form 10-K.

Litigation and Legal Items. We are involved in various legal proceedings. We review the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in our best interests. We have provided the necessary estimated accruals in the accompanying condensed consolidated balance sheets where deemed appropriate for litigation and legal related items that are ongoing and not yet concluded. Although the results cannot be known with certainty, we currently believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations or liquidity.

NOTE 12 - COMMON STOCK

Stock-Based Compensation Plans

2018 Equity Incentive Plan. In May 2020, our stockholders approved an amendment to increase the number of shares of our common stock reserved for issuance pursuant to our long-term equity compensation plan for employees and non-employee directors (the “2018 Plan”) to 7,050,000 shares. As of September 30, 2022, there were 3,834,293 shares available for grant under the 2018 Plan.

2010 Long-Term Equity Compensation Plan. Our Amended and Restated 2010 Long-Term Equity Compensation Plan, approved in 2013 (the “2010 Plan”), remains outstanding and we continue to use the 2010 Plan to grant awards. No awards may be granted under the 2010 Plan on or after June 5, 2023. As of September 30, 2022, there were 240,910 shares available for grant under the 2010 Plan.

The following table provides a summary of the impact of our outstanding stock-based compensation plans on the results of operations for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in thousands)			
General and administrative expense	$ 6,811	$ 5,479	$ 18,731	$ 16,420
Lease operating expense	371	300	1,221	874
Total stock-based compensation expense	$ 7,182	$ 5,779	$ 19,952	$ 17,294

Restricted Stock Units

The following table presents the changes in non-vested time-based RSUs to eligible employees, including executive officers, for the nine months ended September 30, 2022:

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at beginning of period	1,165,187	$ 25.33
Granted	355,539	70.28
Vested	(545,752)	25.80
Forfeited	(41,255)	40.02
Non-vested at end of period	933,719	41.53

The weighted average grant-date fair value of restricted stock units was $70.28 and $33.48 for the nine months ended September 30, 2022 and 2021, respectively. The total grant-date fair value of restricted stock units that vested for the nine months ended September 30, 2022 and 2021 was $14.1 million and $13.3 million, respectively. Total compensation cost related to non-vested time-based awards and not yet recognized on our condensed consolidated statements of operations as of September 30, 2022 was $29.5 million. This cost is expected to be recognized over a weighted average period of 1.6 years.

Performance Stock Units

The Compensation Committee awarded a total of 102,098 market-based PSUs to our executive officers during the nine months ended September 30, 2022. In addition to continuous employment, the vesting of these PSUs is contingent on a combination of absolute stock performance and our total stockholder return (“TSR”), which is essentially our stock price change, including any dividends, over a three-year period ending on December 31, 2024, as compared to the TSR of a group of peer companies over the same period. The PSUs will result in a payout between zero and 250 percent of the target PSUs awarded.

The grant-date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo valuation model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. The expected term of the awards was based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the life of the award. The expected volatility was based on our common stock historical volatility, as well as that of our peer group.

The following table summarizes the key assumptions and related information used to determine the grant-date fair value of performance stock units awarded during the periods presented:

	Nine Months Ended September 30,	
	2022	2021
Expected term of award (in years)	2.9	3.0
Risk-free interest rate	1.7%	0.2%
Expected volatility	86.3%	84.6%
Weighted average grant date fair value per share	$107.85	$54.01

The following table presents the change in non-vested market-based awards during the nine months ended September 30, 2022:

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at beginning of period	439,229	$ 43.21
Granted	102,098	107.85
Granted for performance multiple [1]	241,183	43.10
Released [1]	(241,183)	43.10
Non-vested at end of period	541,327	55.40

(1) Upon completion of the performance period for the PSUs granted in 2019 and a portion of the PSUs granted in 2020, a performance multiple of 190% was applied to each of the grants resulting in additional grants of PSUs in January 2022.

Total compensation cost related to non-vested market-based awards not yet recognized on our condensed consolidated statements of operations as of September 30, 2022 was $14.2 million. This cost is expected to be recognized over a weighted average period of one year.

Preferred Stock

We are authorized to issue 50,000,000 shares of preferred stock, par value $0.01 per share, which may be issued in one or more series, with such rights, preferences, privileges, and restrictions as shall be fixed by our board of directors from time to time. Through September 30, 2022, no shares of preferred stock have been issued.

Stock Repurchase Program

In 2019, our board of directors approved a program pursuant to which we may acquire shares of our common stock from time to time. At December 31, 2021, $187.3 million of the approved $525.0 million remained available for repurchase under the stock repurchase program. In February 2022, our board of directors approved a new stock repurchase program that reset the total repurchase value to $1.25 billion. The stock repurchase program does not require any specific number of shares to be acquired and can be modified or discontinued by our board of directors at any time. Repurchases under the program can be made in open markets at our discretion and in compliance with safe harbor provisions, or in privately negotiated transactions. Pursuant to the program, we repurchased 8.5 million and 2.7 million shares of outstanding common stock at a cost of $561.2 million and $108.3 million during the nine months ended September 30, 2022 and 2021, respectively. As of September 30, 2022, $716.9 million remained available under the program for repurchases of our outstanding common stock.

Dividends

During the first, second, and third quarters of 2022, our board of directors approved the declaration and payment of quarterly cash dividends of $0.25, $0.35, and $0.35 per share of common stock, respectively. For the nine months ended September 30, 2022, our dividends totaled $92.4 million or $0.95 per share of outstanding common stock. All RSUs and PSUs receive a dividend equivalent per unit, recognized as a liability included in other liabilities on our condensed consolidated balance sheets, until the recipients receive the equivalents upon vesting. Dividends declared were recorded as a reduction of retained earnings; however, if there were no retained earnings as of the date of declaration, dividends declared were recorded as a reduction of additional paid-in capital. Future dividend payments must be approved by our board of directors and will depend on our liquidity, financial requirements, and other factors considered relevant by our board.

NOTE 13 - INCOME TAXES

We compute our quarterly tax provision using the effective tax rate method by applying the anticipated annual effective rate to our year-to-date income or loss, except for discrete items. Income tax on discrete items is computed and recorded in the period in which the specific transaction occurs.

We consider whether a portion, or all, of our deferred tax assets (“DTAs”) will be realized based on a more likely than not standard of judgment. The ultimate realization of DTAs is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. At each reporting period, management considers the available taxes in carryback periods, the future reversals of existing taxable temporary differences, tax planning strategies and projected future taxable income in making this assessment. Our oil and gas property impairments and cumulative pre-tax losses were key considerations that led us to provide a valuation allowance against our DTAs beginning January 1, 2020 since we previously could not conclude that it is more likely than not that our DTAs will be fully realized in future periods.

As we previously disclosed in our 2021 Form 10-K, we maintained a valuation allowance on our net federal deferred tax assets and continued to do so until sufficient positive evidence existed to support a reversal of the allowance. In the second quarter of 2022, continued higher commodity prices increased our income, resulting in the reversal of objective negative evidence of cumulative loss in recent years, and we determined that we have sufficient positive evidence to release the valuation allowance. As a result, we released $22.5 million and $45.0 million of the valuation allowance against our deferred income tax assets and recognized a corresponding decrease to income tax expense in the three and nine months ended September 30, 2022, respectively. The remainder of the valuation allowance of $11.6 million will be recognized as a decrease to income tax expense in the fourth quarter of 2022.

Excluding the discrete gain on bargain purchase, the effective income tax rates for the three and nine months ended September 30, 2022 were 22.2 percent and 21.2 percent, respectively, and 0.1 percent and 0.2 percent provision on the respective pre-tax income for the three and nine months ended September 30, 2021, respectively. The effective tax rates differ from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21 percent to the pre-tax income due to state income taxes offset by the effect of the valuation allowance or changes in the valuation allowance against our deferred income tax asset.

As of September 30, 2022, there is no liability for unrecognized income tax benefits. As of the date of this report, we are current with our income tax filings in all applicable state jurisdictions and are not currently under any state income tax examinations. The IRS has accepted our 2020 federal income tax return with no tax adjustments. We continue to voluntarily participate in the IRS CAP program for the review of our 2021 tax year. Participation in the IRS CAP Program has enabled us to have minimal uncertain tax benefits associated with our federal tax return filings.

In August 2022, the Inflation Reduction Act ("IRA") was signed into law. The IRA includes implementation of a new alternative minimum tax, an excise tax on stock buybacks, and significant tax incentives for energy and climate initiatives, among other provisions. The alternative minimum tax and excise tax on stock buyback provisions are effective for tax years beginning after December 31, 2022. We continue to monitor updates to the IRA and the impact to our financial position, results of operations and liquidity, however, we do not believe it will have a material impact on our stock buyback program or our financial position.

NOTE 14 - EARNINGS PER SHARE

Basic earnings per share is computed by dividing net earnings by the weighted average number of common shares outstanding for the period. Diluted earnings per share is similarly computed, except that the denominator includes the effect, using the treasury stock method, of unvested stock-based employee awards and shares held pursuant to our non-employee director deferred compensation plan, if including such potential shares of common stock is dilutive.

The following table presents our weighted average basic and diluted shares outstanding for the periods presented:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2022	**2021**	**2022**	**2021**
	(in thousands)			
Weighted average common shares outstanding - basic	94,950	98,183	96,065	99,018
Dilutive effect of:				
RSUs and PSUs	1,152	1,777	1,376	1,505
Other equity-based awards	20	6	26	11
Weighted average common shares and equivalents outstanding - diluted	96,122	99,966	97,467	100,534

The following table presents the weighted average common share equivalents excluded from the calculation of diluted earnings per share due to their anti-dilutive effect for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in thousands)			
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
RSUs and PSUs	350	6	192	37
Other stock-based awards	32	97	32	131
Total anti-dilutive common share equivalents	382	103	224	168

NOTE 15 - SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

	Nine Months Ended September 30,	
	2022	2021
	(in thousands)	
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$ 36,055	$ 41,880
Income taxes	157	(1,057)
Non-cash investing and financing activities:		
Change in accounts payable related to capital expenditures	$ (10,280)	$ 21,216
Change in asset retirement obligations, with a corresponding change to crude oil and natural gas properties, net of disposals	551	(1,538)
Issuance of common stock for acquisition of an exploration and production business	293,314	—
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 5,752	$ 5,848
Operating cash flows from finance leases	74	77
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases [1]	$ 18,548	$ 1,189
Finance leases	4,157	2,055

(1) Includes $3.1 million operating lease acquired from Great Western.

Cash, cash equivalents and restricted cash presented in the condensed consolidated statements of cash flow is comprised of the following:

	September 30,	
	2022	2021
	(in thousands)	
Cash and cash equivalents	$ 45,649	$ 99,922
Restricted cash [1]	8,130	—
	$ 53,779	$ 99,922

(1) Included in Other assets on our condensed consolidated balance sheets.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our condensed consolidated financial statements and related notes included in *Item 1. Financial Statements* of this report. Further, we encourage you to review the *Special Note Regarding Forward-Looking Statements*.

EXECUTIVE SUMMARY

September 30, 2022 Financial Overview of Operations and Liquidity

Market Conditions

The crude oil and natural gas industry is cyclical and commodity prices are inherently volatile. Commodity prices reflect global supply and demand dynamics as well as the geopolitical and macroeconomic environment.

Crude Oil Markets

During the first nine months of 2022, crude oil pricing has generally increased due to increased demand, restrained OPEC+ production and uncertainties resulting from the Russian invasion of Ukraine. However, the fear of a potential global economic downturn has recently softened the global demand for oil, resulting in a decrease in prices during the third quarter of 2022.

To date in 2022, the U.S. has experienced the highest inflation rates since 1981 resulting mainly from the global recovery from COVID-19, supply chain disruptions, higher labor costs, higher energy costs, and the invasion of Ukraine by Russia. To address the increasing inflation rates, the U.S. Federal Reserve started increasing the benchmark federal funds interest rate. The magnitude and overall effectiveness of these actions remains uncertain, but such monetary policy changes can increase the risk of economic slowdown and/or lead to a recession. A slowdown or recession can cause a decrease or shift in short-term or long-term demand for crude oil, resulting in industry oversupply and a potential for lower commodity prices, which would also impact our drilling program and further increase volatility to our common stock price.

Natural Gas and NGL Markets

In addition to the crude oil market drivers noted above, natural gas and NGL prices are also affected by structural changes in supply and demand, growth in levels of liquified natural gas and liquified petroleum gas exports and deviations from seasonally normal weather. Lower inventory levels and lack of reinvestment in supply growth have driven natural gas and NGL prices higher in 2022.

Financial Matters

Three months ended September 30, 2022 compared to three months ended June 30, 2022

- Production volumes increased to 23.0 MMboe in the third quarter of 2022, an increase of 7 percent compared to 21.4 MMboe in the second quarter, primarily driven by three months of production volumes from the Great Western Acquisition in the third quarter of 2022 compared to two months of production volumes from the Great Western Acquisition in the second quarter of 2022.

- Crude oil, natural gas and NGLs sales decreased to $1,200.6 million compared to $1,237.7 million in the second quarter of 2022 primarily due to a 10 percent decrease in weighted average realized commodity prices, partially offset by a 7 percent increase in production volumes between periods.

- Negative net cash settlements from our commodity derivative contracts decreased to $252.8 million in the third quarter of 2022 compared to $298.7 million in the second quarter of 2022 due to a decrease in commodity prices between periods.

- Combined revenues from crude oil, natural gas and NGLs sales and net settlements from our commodity derivative instruments increased 1 percent to $947.8 million from $939.0 million in the second quarter of 2022.

- Net income increased to $798.0 million, or $8.30 per diluted share, for the third quarter of 2022 compared to $662.4 million, or $6.74 per diluted share, in the second quarter of 2022 primarily due to a $306.7 million commodity risk management gain in the third quarter of 2022 compared to a $102.0 million commodity risk management loss in the second quarter of 2022, partially offset by (i) a gain on bargain purchase from the Great Western Acquisition of $100.3 million recognized in the second quarter, (ii) an increase in income tax expense of $101.3 million, and (iii) a decrease in crude oil, natural gas and NGLs sales of $37.1 million.

- Adjusted EBITDAX, a non-U.S. GAAP financial measure, decreased to $714.6 million compared to $814.3 million for the second quarter of 2022 primarily due to a $100.3 million gain on bargain purchase recognized in the second quarter of 2022.

- Cash flows from operations increased to $848.4 million compared to $747.4 million in the second quarter of 2022 primarily due to changes in working capital between periods. Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased to $701.3 million compared to $694.7 million in the second quarter of 2022. Adjusted free cash flows, a non-U.S. GAAP financial measure, increased to $440.4 million from $403.8 million in the second quarter of 2022.

Nine months ended September 30, 2022 compared to nine months ended September 30, 2021

- Production volumes increased to 62.3 MMboe in 2022, an increase of 20 percent compared to 51.9 MMboe in 2021, primarily driven by production volumes from the Great Western Acquisition and as a result of our turn-in-line activities in 2022.

- Crude oil, natural gas and NGLs sales increased to $3.3 billion compared to $1.7 billion in 2021 primarily due to a 62 percent increase in weighted average realized commodity prices and a 20 percent increase in production volumes between periods.

- Negative net cash settlements from our commodity derivative contracts increased to $713.1 million in 2022 compared to $215.4 million in 2021 due to improvements in commodity pricing year over year and additional commodity derivatives acquired from the Great Western Acquisition.

- Combined revenues from crude oil, natural gas and NGLs sales and net settlements from our commodity derivative instruments increased 75 percent to $2.6 billion from $1.5 billion in 2021.

- Net income increased to $1,428.4 million, or $14.66 per diluted share, in the 2022 period compared to a net income of $49.2 million, or $0.49 per diluted share, in the 2021 period, primarily due to (i) an increase in crude oil, natural gas and NGLs sales of $1,616.3 million, (ii) a $343.9 million decrease in risk management loss and (iii) a gain on bargain purchase from the Great Western Acquisition of $95.7 million, partially offset by a $228.7 million increase in production costs and a $358.4 million increase in income tax expense between periods.

- Adjusted EBITDAX, a non-U.S. GAAP financial measure, increased to $2,078.0 million in 2022 compared to $1,106.0 million in 2021, primarily due to an increase in sales of $1,118.6 million, net of negative net derivative settlements, and a $95.7 million gain on bargain purchase recognized in 2022, partially offset by an increase in costs experienced in operations between periods.

- Cash flows from operations increased to $2,084.8 million in 2022 compared to $1,027.8 million in 2021 primarily due to a 62 percent increase in weighted average realized sales prices and a 20 percent increase in production volumes between periods. Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased to $1,934.7 million in 2022 compared to $1,059.5 million in 2021. Adjusted free cash flows, a non-U.S. GAAP financial measure, increased to $1,163.0 million in 2022 from $609.5 million in 2021.

See *Reconciliation of Non-U.S. GAAP Financial Measures* below for a more detailed discussion of these non-U.S. GAAP financial measures and a reconciliation of these measures to the most comparable U.S. GAAP measures.

Great Western Acquisition

On May 6, 2022, we completed the acquisition of Great Western for approximately $1.4 billion, inclusive of Great Western's net debt. Great Western was an independent oil and gas company focused on the exploration, production and development of crude oil and natural gas in the Wattenberg Field of Colorado. The consideration paid was $542.5 million in cash and approximately 4.0 million shares of our common stock, valued at $293.3 million on the acquisition date. In addition, we paid off Great Western's secured credit facility totaling $235.8 million, and paid $361.2 million to terminate Great Western's 12% senior secured notes due 2025, inclusive of unpaid accrued interest and a premium for early termination. The cash portion of the purchase price and the termination of Great Western's debt were funded through a combination of cash on hand and availability under our revolving credit facility. As a result of the Great Western Acquisition, we acquired approximately 54,000 net acres in the core Wattenberg Field and production of approximately 50,000 Boe per day.

Drilling and Completion Overview

In the Wattenberg Field, we operated one full-time drilling rig and one full-time completion crew during the first nine months of 2022, added a second full-time drilling rig in March 2022 and a third full-time drilling rig plus an intermittent completion crew upon closing the Great Western Acquisition. In addition, we operated one full-time drilling rig during the first nine months of 2022 and had one completion crew in the first half of 2022 in the Delaware Basin. Our total capital investments in crude oil and natural gas properties for the nine months ended September 30, 2022 were $763.9 million.

The following table summarize our drilling and completion activities for the nine months ended September 30, 2022:

	Operated Wells					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2021	143	133.0	21	20.6	164	153.6
Wells spud	121	111.8	13	12.9	134	124.7
Wells acquired in-process (1)	48	41.4	—	—	48	41.4
Wells turned-in-line	(114)	(104.7)	(19)	(18.8)	(133)	(123.5)
Developmental and exploratory dry hole	(1)	(0.7)	(3)	(3.0)	(4)	(3.7)
In-process as of September 30, 2022	197	180.8	12	11.7	209	192.5

(1) Represents in-process wells we obtained as part of the Great Western Acquisition.

Our in-process wells represent wells that are in the process of being drilled or have been drilled and are waiting to be fractured and/or for gas pipeline connection. Our in-process wells are generally completed and turned-in-line within two years of drilling.

Capital Returns

Stock Repurchase Program. In February 2022, our board of directors approved a new stock repurchase program that reset the total repurchase value to $1.25 billion, which we currently anticipate fully utilizing by December 31, 2023. We repurchased 8.5 million shares of outstanding common stock at a cost of $561.2 million for the nine months ended September 30, 2022. As of September 30, 2022, $716.9 million remained available for repurchases under the program.

Dividends. Our board of directors approved the declaration and payment of a quarterly cash dividend of $0.25 per share of common stock in the first quarter of 2022 and increased our base quarterly dividend to $0.35 per share of common stock in the second quarter of 2022. For the nine months ended September 30, 2022, our dividends totaled $92.4 million or $0.95 per share of outstanding common stock.

2022 Operational and Financial Outlook

We anticipate that our full-year 2022 production will range between 230,000 Boe and 240,000 Boe per day, of which approximately 73,000 Bbls to 77,000 Bbls is expected to be crude oil. Our planned 2022 capital investments in crude oil and natural gas properties, which we expect to be at the upper end of the range of $1.025 billion to $1.075 billion, are focused on continued execution of our development plans in the Wattenberg Field and the Delaware Basin. Our capital budget and operating costs for 2022 will continue to be impacted by cost inflation, supply chain constraints and availability of labor services.

We have operational flexibility to control the pace of our capital spending. As we execute our capital investment program, we continually monitor, among other things, expected rates of return, the political environment and our remaining inventory to best meet our short- and long-term corporate strategy.

Wattenberg Field. We are drilling in the horizontal Niobrara and Codell plays in the rural areas of the core Wattenberg Field, which is further delineated between the Kersey, Prairie, Plains, Summit and Range development areas. Our 2022 capital investment program for the Wattenberg Field represents approximately 80 percent of our expected total capital investments in crude oil and natural gas properties. In 2022, we plan to drill between 1.5 and 3.0 mile lateral wells. Our plan includes spudding and turning-in-line approximately 150 to 175 operated wells. To meet our development plan, we intend on running three full-time horizontal rigs and one full-time completion crew plus an intermittent completion crew for the rest of the year.

Delaware Basin. Total capital investments in crude oil and natural gas properties in the Delaware Basin for 2022 are expected to be approximately 20 percent of our total capital investments. In 2022, we anticipate spudding 16 operated wells and turning-in-line 20 operated wells with the majority of the wells being between 1.5 and 3.0 mile lateral wells. We completed our 2022 completion program in late May and are currently running one full-time drilling rig.

We are committed to our disciplined approach to managing our development plans. Based on our current production forecast for 2022, we expect 2022 cash flows from operations to exceed our capital investments in crude oil and natural gas properties. Our first priority is to pay our quarterly base dividend of $0.35 per share. Then we expect to use approximately 60% or more of our remaining adjusted free cash flow, a non-U.S. GAAP financial measure, for share repurchases and special dividends, as needed. Any remaining adjusted free cash flows will be used for reducing debt, building cash on our consolidated balance sheet or other general corporate purposes.

Regulatory and Political Updates

In Colorado, certain interest groups opposed to oil and natural gas development have proposed ballot initiatives that could hinder or eliminate the ability to develop resources in the state. In 2019, the Colorado legislature passed Senate Bill 19-181 (“SB 19-181”) to address concerns underlying the ballot initiatives.

A key component of SB 19-181 was the change in the COGCC mission from “fostering” the industry to “regulating” the industry. As a result, changes were made to the permitting process in Colorado. Permits are now granted as part of Oil and Gas Development Plans (“OGDP”), a process that streamlines single pad locations or proximate multi-pad locations into a single permitting package.

Operators also have an option to pursue a Comprehensive Area Plan (“CAP”). A CAP is designed to represent an overview of oil and gas development over a larger area over a longer period of time, including a comprehensive cumulative impact analysis, an alternative location analysis, and extensive communication with both local elected officials and communities. A CAP will include multiple OGDPs within its boundaries. COGCC rules provide that the permitting process could range between six to twelve months or more from submission to approval.

In addition to the changes to the permitting process, the COGCC conducted a rulemaking concerning financial assurance to be provided by operators in Colorado. The rulemaking was designed to reduce the number of wells that have not been properly plugged by their operators (“orphan wells”) due to financial constraints or bankruptcy. As part of that rulemaking, tiers of operators were established based on identified metrics with operators in different tiers being obligated to provide different levels of financial assurance. For our tier, a bond of $40 million will be required by early 2023 and will be secured through our existing surety bond program. In addition to the financial assurance, operators will be assessed an annual fixed fee per existing well that will fund the plugging and abandonment of orphan wells identified by the COGCC. We do not anticipate a material effect on our financial condition or results of operations with meeting the outlined financial assurance requirements.

We cannot predict whether future ballot initiatives or other legislation or regulation will be proposed that would limit the areas of the state in which drilling is permitted to occur or impose other requirements or restrictions.

Wattenberg Permits Update. In June 2022, the COGCC granted PDC unanimous approval for a 69-well OGDP and a 30-well OGDP, our second and third approvals under the new permitting process. Combined, these two approvals provided us approximately 100 additional permits for our 2024 drilling and completion plan. We have established robust permit application and submission processes as part of our day-to-day operations.

In December 2021, PDC submitted our first CAP. The application proposes approximately 450 wells spread amongst 22 surface locations, to be developed over several years. We conducted a comprehensive analysis of potential impacts and have committed to transport all water and commodity production via pipeline and to provide electrical infrastructure to all locations. These commitments will lessen the impact of traffic, noise, light and emissions, while also improving our ESG metrics. Additionally, we developed a dashboard to analyze disproportionately impacted communities in the area and developed a robust communication plan designed to encourage communication with and garner feedback from these key stakeholders. A 60-day public comment period expired on October 2, 2022 and public hearings before the COGCC are tentatively scheduled for December 7, 2022. We anticipate a COGCC determination on approval of our CAP by year end 2022 or early 2023. Following the approval of the CAP, we will submit individual OGDP packages for each of the locations within the approved CAP. Due to our proactive assessment of all potential locations for the pads within the OGDPs located within our CAP. Once approved, PDC has a right conveyed by COGCC for expedited review. We anticipate submitting these OGDPs in a cadence designed to reflect our multi-year drilling plan. The CAP, along with our prior OGDPs, represent our planned Wattenberg Field turn-in-line activity past 2028.

Environmental, Social and Governance (“ESG”)

We are committed to a meaningful and measurable ESG strategy. Our mission to be a cleaner, safer and more socially responsible company begins with a sound strategy, is supported in the boardroom and is overseen by our Environmental, Social, Governance and Nominating Committee at the board of directors and is considered at every level of our business.

In September 2022, we issued our annual Sustainability reports. The reports include key metrics and data from 2021 operations and are aligned with Sustainable Accounting Standards Board (“SASB”) and, as a first for PDC, the Taskforce on Climate-Related Financial Disclosure (“TFCD”). Additional information on our ESG practices, including sustainability goals, key metrics and progress achieved, can be found on our Sustainability page of our website at www.pdce.com. The information on our website, including the Sustainability reports, is not incorporated by reference in this report.

The SEC and other regulatory bodies are proposing a number of climate-change focused and broader ESG reporting requirements focused on emission reduction. When adopted, we will modify our disclosures accordingly.

Results of Operations

Summary of Operating Results

The following table presents selected information regarding our operating results:

	Three Months Ended			Nine Months Ended		
	September 30, 2022	June 30, 2022	Percent Change	September 30, 2022	September 30, 2021	Percent Change
			(dollars in millions, except per unit data)			
Production:						
Crude oil (MBbls)	7,409	6,844	8 %	20,106	16,357	23 %
Natural gas (MMcf)	52,947	49,817	6 %	145,883	128,714	13 %
NGLs (MBbls)	6,747	6,263	8 %	17,895	14,119	27 %
Crude oil equivalent (MBoe)	22,980	21,410	7 %	62,315	51,928	20 %
Average Boe per day (Boe)	249,783	235,275	6 %	228,260	190,212	20 %
Crude Oil, Natural Gas and NGLs Sales:						
Crude oil	$ 680.7	$ 740.9	(8)%	$ 1,971.3	$ 1,046.9	88 %
Natural gas	319.2	277.7	15 %	760.0	326.9	132 %
NGLs	200.7	219.1	(8)%	589.4	330.6	78 %
Total crude oil, natural gas and NGLs sales	$ 1,200.6	$ 1,237.7	(3)%	$ 3,320.7	$ 1,704.4	95 %
Net Settlements on Commodity Derivatives					`	
Crude oil	$ (146.9)	$ (231.4)	(37)%	$ (509.4)	$ (166.4)	206 %
Natural gas	(105.9)	(67.3)	57 %	(203.7)	(49.0)	*
Total net settlements on derivatives	$ (252.8)	$ (298.7)	(15)%	$ (713.1)	$ (215.4)	231 %
Average Sales Price (excluding net settlements on derivatives):						
Crude oil (per Bbl)	$ 91.88	$ 108.24	(15)%	$ 98.05	$ 64.00	53 %
Natural gas (per Mcf)	6.03	5.57	8 %	5.21	2.54	105 %
NGLs (per Bbl)	29.75	34.99	(15)%	32.93	23.41	41 %
Crude oil equivalent (per Boe)	52.25	57.81	(10)%	53.29	32.82	62 %
Average Costs and Expenses (per Boe):						
Lease operating expense	$ 3.01	$ 3.30	(9)%	$ 3.11	$ 2.50	24 %
Production taxes	4.27	4.17	2 %	4.02	1.95	106 %
Transportation, gathering and processing expense	1.41	1.38	2 %	1.44	1.43	1 %
General and administrative expense	1.75	2.13	(18)%	1.92	1.86	3 %
Depreciation, depletion and amortization	8.95	8.92	— %	8.79	9.22	(5)%
Lease Operating Expense by Operating Region (per Boe)						
Wattenberg Field	$ 2.46	$ 2.85	(14)%	$ 2.58	$ 2.20	17 %
Delaware Basin	6.92	5.98	16 %	6.50	4.50	44 %

* *Percent change is not meaningful.*

Crude Oil, Natural Gas and NGLs Sales

The change in crude oil, natural gas and NGLs sales for the three months ended September 30, 2022 compared to the three months ended June 30, 2022 and the nine months ended September 30, 2022 compared to the nine months ended September 30, 2021 were due to the following:

	Change Between	
	June 30, 2022 - September 30, 2022	September 30, 2021 - September 30, 2022
	(in millions)	
Change in:		
Production	$ 95.4	$ 372.0
Average crude oil price	(121.2)	684.4
Average natural gas price	24.0	389.5
Average NGLs price	(35.3)	170.4
Total change in crude oil, natural gas and NGLs sales revenue	$ (37.1)	$ 1,616.3

Crude Oil, Natural Gas and NGLs Production

The following table presents crude oil, natural gas and NGLs production for the periods presented:

	Three Months Ended			Nine Months Ended		
Production by Operating Region	**September 30, 2022**	**June 30, 2022**	**Percent Change**	**September 30, 2022**	**September 30, 2021**	**Percent Change**
Crude oil (MBbls)						
Wattenberg Field	6,299	5,545	14 %	16,676	13,595	23 %
Delaware Basin	1,110	1,299	(15)%	3,430	2,762	24 %
Total	7,409	6,844	8 %	20,106	16,357	23 %
Natural gas (MMcf)						
Wattenberg Field	46,631	43,244	8 %	127,538	113,280	13 %
Delaware Basin	6,316	6,573	(4)%	18,345	15,434	19 %
Total	52,947	49,817	6 %	145,883	128,714	13 %
NGLs (MBbls)						
Wattenberg Field	6,083	5,575	9 %	15,949	12,685	26 %
Delaware Basin	664	688	(3)%	1,946	1,434	36 %
Total	6,747	6,263	8 %	17,895	14,119	27 %
Crude oil equivalent (MBoe)						
Wattenberg Field	20,153	18,328	10 %	53,881	45,160	19 %
Delaware Basin	2,827	3,082	(8)%	8,434	6,768	25 %
Total	22,980	21,410	7 %	62,315	51,928	20 %
Average crude oil equivalent per day (Boe)						
Wattenberg Field	219,055	201,407	9 %	197,366	165,421	19 %
Delaware Basin	30,728	33,868	(9)%	30,894	24,791	25 %
Total	249,783	235,275	6 %	228,260	190,212	20 %

Net production volumes for oil, natural gas and NGLs increased 7 percent during the three months ended September 30, 2022 compared to the three months ended June 30, 2022 primarily due to approximately 1.6 MMboe of additional production volumes from the Great Western Acquisition. The increase was partially offset by a decrease in production from Delaware Basin as a result of no turn-in-line activities in the third quarter of 2022 and normal decline in production from existing wells.

Net production volumes for oil, natural gas and NGLs increased 20 percent during the nine months ended September 30, 2022 compared to the same period in 2021. The increase in production volume between periods was primarily due to approximately 7.7 MMboe of additional production volumes from the Great Western Acquisition and the net impact of turn-in-line activities in both basins since the third quarter of 2021 and normal production decline from existing wells.

The following table presents our crude oil, natural gas and NGLs production ratio by operating region for the periods presented:

	Three Months Ended September 30, 2022			
	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	31%	39%	30%	100%
Delaware Basin	39%	37%	24%	100%

	Three Months Ended June 30, 2022			
	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	30%	39%	31%	100%
Delaware Basin	42%	36%	22%	100%

	Nine Months Ended September 30, 2022			
	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	31%	39%	30%	100%
Delaware Basin	41%	36%	23%	100%

	Nine Months Ended September 30, 2021			
	Crude Oil	Natural Gas	NGLs	Total
Wattenberg Field	30%	42%	28%	100%
Delaware Basin	41%	38%	21%	100%

Midstream Capacity

Our ability to market our production depends substantially on the availability, proximity and capacity of in-field gathering systems, compression, and processing facilities, as well as transportation pipelines out of the basin, all of which are owned and operated by third parties. If adequate midstream facilities and services are not available on a timely basis and at acceptable costs, our production and results of operations could be adversely affected.

The ultimate timing and availability of adequate infrastructure remains out of our control. Weather, regulatory developments, preventative routine maintenance and other factors also affect the adequacy of midstream infrastructure. Like other producers, from time to time, we enter into volume commitments with midstream providers in order to incentivize them to provide increased capacity to meet our projected volume growth from our areas of operation. If our production falls below the level required under these agreements, we could be subject to transportation charges or aid in construction payments for commitment shortfalls.

Our production from the Wattenberg Field and Delaware Basin was not materially affected by midstream or downstream capacity constraints during the nine months ended September 30, 2022. We continuously monitor infrastructure capacities versus producer activity and production volume forecasts. Increases in crude oil and natural gas prices in the first nine months of 2022 have incentivized producers in the Permian Basin to increase the level of drilling and completion activities. The potential increase in production levels may lead to natural gas transportation constraints out of the Permian Basin by the end of 2022 or in 2023, which may result to lower realized Waha natural gas prices. However, a majority of PDC’s gas production in the Delaware Basin is dedicated to the Permian Highway Pipeline and is exposed to Houston-based gas pricing. We believe that this reduces the risk of a decrease in realized natural gas prices related to transportation constraints is reduced.

Crude Oil, Natural Gas and NGLs Pricing

Our results of operations depend upon many factors. Key factors include market prices of crude oil, natural gas and NGLs and our ability to market our production effectively. Crude oil, natural gas and NGLs prices have a high degree of volatility and our realizations can change substantially.

The following table presents weighted average sales prices of crude oil, natural gas and NGLs for the periods presented:

Weighted Average Realized Sales Price by Operating Region *(excluding net settlements on derivatives)*	Three Months Ended			Nine Months Ended		
	September 30, 2022	June 30, 2022	Percent Change	September 30, 2022	September 30, 2021	Percent Change
Crude oil (per Bbl)						
Wattenberg Field	$ 91.68	$ 108.05	(15)%	$ 97.66	$ 63.94	53 %
Delaware Basin	93.00	109.06	(15)%	99.93	64.31	55 %
Weighted average price	91.88	108.24	(15)%	98.05	64.00	53 %
Natural gas (per Mcf)						
Wattenberg Field	$ 5.94	$ 5.50	8 %	$ 5.16	$ 2.54	103 %
Delaware Basin	6.66	6.09	9 %	5.53	2.52	119 %
Weighted average price	6.03	5.57	8 %	5.21	2.54	105 %
NGLs (per Bbl)						
Wattenberg Field	$ 28.06	$ 32.56	(14)%	$ 30.79	$ 22.32	38 %
Delaware Basin	45.26	54.62	(17)%	50.49	33.08	53 %
Weighted average price	29.75	34.99	(15)%	32.93	23.41	41 %
Crude oil equivalent (per Boe)						
Wattenberg Field	$ 50.87	$ 55.57	(8)%	$ 51.56	$ 31.90	62 %
Delaware Basin	62.04	71.13	(13)%	64.33	39.01	65 %
Weighted average price	52.25	57.81	(10)%	53.29	32.82	62 %

Crude oil, natural gas and NGLs revenues are recognized when we transfer control of crude oil, natural gas or NGLs production to the purchaser. We consider the transfer of control to occur when the purchaser has the ability to direct the use of, and obtain substantially all of the remaining benefits from the crude oil, natural gas or NGLs production.

Our crude oil, natural gas and NGLs sales are recorded using either the “net-back” or “gross” method of accounting, depending upon the related purchase agreement. We use the net-back method when control of the crude oil, natural gas or NGLs has been transferred to the purchasers of these commodities that are providing transportation, gathering or processing services. In these situations, the purchaser pays us based on a percent of proceeds or a sales price fixed at index less specified deductions. The net-back method results in the recognition of a net sales price that is lower than the index on which the production is based because the operating costs and profit of the midstream facilities are embedded in the net price we are paid. We use the gross method of accounting when control of the crude oil, natural gas or NGLs is not transferred to the purchaser and the purchaser does not provide transportation, gathering or processing services as a function of the price we receive. Rather, we contract separately with midstream providers for the applicable transportation and processing on a per unit basis. Under this method, we recognize revenues based on the gross selling price and recognize transportation, gathering and processing (“TGP”) expense.

Information related to the components and classifications of TGP expense on the condensed consolidated statements of operations is shown below. For crude oil, the average NYMEX prices shown below are based on average daily prices throughout each month and, for natural gas, the average NYMEX pricing is based on first-of-the-month index prices, as in each case this is the method used to sell the majority of these commodities pursuant to terms of the relevant sales agreements. For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes. The average realized price both before and after TGP expense shown in the table below represents our approximate composite per barrel price for NGLs for the periods presented.

Three Months Ended September 30, 2022	Average NYMEX Price	Average Realized Price Before TGP Expense	Average Realization Percentage Before TGP Expense	Average TGP Expense (1)	Average Realized Price After TGP Expense	Average Realization Percentage After TGP Expense
Crude oil (per Bbl)	$ 91.56	$ 91.88	100 %	$ 2.50	$ 89.38	98 %
Natural gas (per MMBtu)	8.20	6.03	74 %	0.19	5.84	71 %
NGLs (per Bbl)	91.56	29.75	32 %	—	29.75	32 %
Crude oil equivalent (per Boe)	75.28	52.25	69 %	1.23	51.02	68 %

Three Months Ended June 30, 2022	Average NYMEX Price	Average Realized Price Before TGP Expense	Average Realization Percentage Before TGP Expense	Average TGP Expense (1)	Average Realized Price After TGP Expense	Average Realization Percentage After TGP Expense
Crude oil (per Bbl)	$ 108.41	$ 108.24	100 %	$ 2.37	$ 105.87	98 %
Natural gas (per MMBtu)	7.17	5.58	78 %	0.22	5.36	75 %
NGLs (per Bbl)	108.41	34.99	32 %	—	34.99	32 %
Crude oil equivalent (per Boe)	83.05	57.81	70 %	1.26	56.55	68 %

Nine Months Ended September 30, 2022	Average NYMEX Price	Average Realized Price Before TGP Expense	Average Realization Percentage Before TGP Expense	Average TGP Expense (1)	Average Realized Price After TGP Expense	Average Realization Percentage After TGP Expense
Crude oil (per Bbl)	$ 98.09	$ 98.05	100 %	$ 2.59	$ 95.46	97 %
Natural gas (per MMBtu)	6.77	5.21	77 %	0.21	5.00	74 %
NGLs (per Bbl)	98.09	32.93	34 %	—	32.93	34 %
Crude oil equivalent (per Boe)	75.67	53.29	70 %	1.32	51.97	69 %

Nine Months Ended September 30, 2021	Average NYMEX Price	Average Realized Price Before TGP Expense	Average Realization Percentage Before TGP Expense	Average TGP Expense (1)	Average Realized Price After TGP Expense	Average Realization Percentage After TGP Expense
Crude oil (per Bbl)	$ 64.82	$ 64.00	99 %	$ 3.25	$ 60.75	94 %
Natural gas (per MMBtu)	3.18	2.54	80 %	0.12	2.42	76 %
NGLs (per Bbl)	64.82	23.41	36 %	—	23.41	36 %
Crude oil equivalent (per Boe)	45.92	32.82	71 %	1.33	31.49	69 %

(1) Average TGP expense excludes unutilized firm transportation fees of $0.18 per Boe and $0.12 per Boe for the three months ended September 30, 2022 and June 30, 2022, respectively, and 0.12 and $0.10 per Boe for the nine months ended September 30, 2022 and 2021, respectively.

Our average realization percentages for crude oil, natural gas and NGLs were relatively flat for the three months ended September 30, 2022 as compared to the three months ended June 30, 2022.

Our average realization percentage for crude oil increased for the nine months ended September 30, 2022 as compared to the same period in 2021 primarily due to an increased demand for crude oil, global supply disruptions and geopolitical issues.

In addition, we realized improved differentials from our 2022 crude oil sales contracts. Average realization percentage for natural gas decreased for the nine months ended September 30, 2022 compared to the nine months ended September 30, 2021 due to strong pricing in February 2021 as a result of severe weather conditions.

Commodity Price Risk Management

We use commodity derivative instruments to manage fluctuations in crude oil and natural gas prices, including collars, fixed-price exchanges, and basis protection exchanges on a portion of our estimated crude oil and natural gas production. For our commodity exchanges, we ultimately realize the fixed price value related to the swaps. See *Note 5 - Commodity Derivative Financial Instruments* in *Item 1. Financial Statements* included elsewhere in this report for a summary of our derivative positions as of September 30, 2022.

Commodity price risk management, net, includes cash settlements upon maturity of our derivative instruments, and the change in fair value of unsettled commodity derivatives related to our crude oil and natural gas production.

Net settlements of commodity derivative instruments are based on the difference between the crude oil and natural gas index prices at the settlement date of our commodity derivative instruments compared to the respective strike prices contracted for the settlement months that were established at the time we entered into the commodity derivative transaction. The net change in fair value of unsettled commodity derivatives is comprised of the net increase or decrease in the beginning-of-period fair value of commodity derivative instruments that settled during the period and the net change in fair value of unsettled commodity derivatives during the period or from inception of any new contracts entered into during the applicable period. The net change in fair value of unsettled commodity derivatives during the period is primarily related to shifts in the crude oil and natural gas forward price curves and changes in certain differentials.

The following table presents net settlements and net change in fair value of unsettled derivatives included in commodity price risk management, net:

	Three Months Ended		Nine Months Ended	
	September 30, 2022	June 30, 2022	September 30, 2022	September 30, 2021
	(in millions)			
Commodity price risk management gain (loss), net:				
Net settlements of commodity derivative instruments:				
Crude oil collars and fixed price exchanges	$ (146.9)	$ (231.4)	$ (509.4)	$ (166.4)
Natural gas collars and fixed price exchanges	(115.6)	(75.7)	(219.4)	(40.1)
Natural gas basis protection exchanges	9.6	8.4	15.7	(8.9)
Total net settlements of commodity derivative instruments	(252.9)	(298.7)	(713.1)	(215.4)
Change in fair value of unsettled commodity derivative instruments:				
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	250.2	173.9	231.1	20.4
Crude oil collars and fixed price exchanges	370.7	(6.6)	213.0	(326.0)
Natural gas collars and fixed price exchanges	(88.5)	41.4	(110.4)	(185.0)
Natural gas basis protection exchanges	27.2	(12.0)	16.1	(1.2)
Net change in fair value of unsettled commodity derivative instruments	559.6	196.7	349.8	(491.8)
Total commodity price risk management gain (loss), net	$ 306.7	$ (102.0)	$ (363.3)	$ (707.2)

The decrease in commodity prices during the three months ended September 30, 2022 compared to the three months ended June 30, 2022 resulted in an unrealized commodity risk management gain in the third quarter of 2022. The overall increase in commodity prices during the nine months ended September 30, 2022 and September 30, 2021 had an unfavorable impact on the fair value and settlements of our commodity derivatives.

Lease Operating Expense

Lease operating expense ("LOE") decreased by 2 percent to $69.2 million for the three months ended September 30, 2022 compared to $70.6 million for the three months ended June 30, 2022. The period-over-period decrease in LOE was primarily attributable to a $2.6 million decrease in non-operated projects partially offset by an additional month of expense from Great Western during the three months ended September 30, 2022. LOE per Boe decreased 9 percent to $3.01 for the three months ended September 30, 2022 from $3.30 for the three months ended June 30, 2022. The decrease in LOE per Boe was primarily due to the factors outlined above and a 7 percent increase in production volumes between periods.

LOE increased by 49 percent to $193.9 million for the nine months ended September 30, 2022 compared to $129.8 million for the nine months ended September 30, 2021. The period-over-period increase in LOE was primarily due to (i) an increase of approximately $34.3 million as a result of the Great Western Acquisition, increased activity and the impact of inflation in the Wattenberg Field, (ii) a $12.5 million increase in workover expense due to the timing of workover activities focused mainly in the Delaware Basin, (iii) a $10.2 million increase in chemical treatments, water disposal and well services in the Delaware Basin as a result of increased activity and the impact of inflation and (iv) a $4.3 million increase in non-operated costs resulting from increased activities in both basins. LOE per Boe increased 24 percent to $3.11 for the nine months ended September 30, 2022 from $2.50 for the nine months ended September 30, 2021, an increase that was primarily due to the additional costs outlined above partially offset by a 20 percent increase in production volumes between periods.

Production Taxes

Production taxes are comprised mainly of severance tax and ad valorem tax, and are directly related to crude oil, natural gas and NGLs sales and are generally assessed as a percentage of net revenues. From time to time, there are adjustments to the statutory rates for these taxes based upon certain credits that are determined based upon activity levels and relative commodity prices from year-to-year.

Production taxes increased 10 percent to $98.1 million for the three months ended September 30, 2022 compared to $89.3 million for the three months ended June 30, 2022. Production taxes per Boe increased 2 percent to $4.27 for the three months ended September 30, 2022 compared to $4.17 for the three months ended June 30, 2022. The increase in production taxes per Boe between periods was primarily due to higher production tax rates in the counties where the wells we turned-in-line during the third quarter were located.

Production taxes increased 148 percent to $250.3 million for the nine months ended September 30, 2022 compared to $101.1 million for the nine months ended September 30, 2021. The increase in production taxes was primarily due to an increase in crude oil, natural gas and NGLs prices between periods and additional production volumes from the Great Western Acquisition. Production taxes per Boe increased 106 percent to $4.02 for the nine months ended September 30, 2022 compared to $1.95 for the nine months ended September 30, 2021 due to an increase in crude oil, natural gas and NGLs prices between periods.

Transportation, Gathering and Processing Expense

TGP expense increased 9 percent to $32.3 million for the three months ended September 30, 2022 compared to $29.6 million for the three months ended June 30, 2022. The increase in TGP expense between periods was primarily due a 7 percent increase in production volumes between periods. TGP expense per Boe increased 2 percent to $1.41 for the three months ended September 30, 2022 compared to $1.38 for the three months ended June 30, 2022.

TGP expense increased 21 percent to $89.9 million for the nine months ended September 30, 2022 compared to $74.5 million for the nine months ended September 30, 2021. The increase in TGP expense between periods was primarily due to an increase in gas processing volumes and rates in the Delaware Basin. TGP expense per Boe increased 1 percent to $1.44 for the nine months ended September 30, 2022 compared to $1.43 for the nine months ended September 30, 2021. TGP expense per Boe for the nine months ended September 30, 2022 compared to the same period in 2021 was relatively flat due to the net impact of lower TGP rates on the acquired Great Western production volumes offset by higher gas processing costs in the Delaware Basin.

Exploration, Geologic, and Geophysical Expense

Exploration, geologic and geophysical expense increased to $11.8 million for the three months ended September 30, 2022 compared to $0.3 million for the three months ended June 30, 2022 and increased to $12.4 million for the nine months ended September 30, 2022 compared to $0.9 million for the same period in the prior year. During the nine months ended September 30, 2022, we drilled and turned-in-line an exploratory well in the Delaware Basin that was not economically viable. During the third quarter of 2022, we expensed the associated lease costs and related infrastructure assets of the exploratory dry hole at a cost of $11.5 million.

Impairment of Properties and Equipment

There were no significant impairment charges recognized related to our proved and unproved oil and gas properties for the three months ended September 30, 2022 or June 30, 2022 or for the nine months ended September 30, 2022 or 2021. If crude oil prices decline, or we change other estimates impacting future net cash flows (e.g. reserves, price differentials, future operating and/or development costs), our proved and unproved oil and gas properties could be subject to additional impairments in future periods.

General and Administrative Expense

General and administrative expense decreased 12 percent to $40.1 million for the three months ended September 30, 2022 compared to $45.6 million for the three months ended June 30, 2022, primarily due to a $4.9 million decrease in professional service fees related to the Great Western Acquisition transaction and transition costs.

General and administrative expense increased 24 percent to $119.9 million for the nine months ended September 30, 2022 compared to $96.4 million for the nine months ended September 30, 2021, primarily due to $17.9 million in transaction and transition costs relating to the Great Western Acquisition.

Depreciation, Depletion and Amortization Expense

DD&A expense related to crude oil and natural gas properties is directly related to proved reserves and production volumes. DD&A expense related to crude oil and natural gas properties was $203.6 million for the three months ended September 30, 2022 compared to $189.1 million for the three months ended June 30, 2022. The increase in DD&A expense was primarily due to a 7 percent increase in production volumes as a result of having three months of production volumes from the Great Western Acquisition in the third quarter of 2022 compared to two months of production volumes from the Great Western Acquisition in the second quarter of 2022.

DD&A expense related to crude oil and natural gas properties was $542.0 million for the nine months ended September 30, 2022 compared to $472.7 million for the comparable period in 2021. The increase in total DD&A expense was primarily due to a 20 percent increase in production volumes between periods from the Great Western Acquisition and capitalized costs for wells turned-in-line since the third quarter of 2021. These increases were partially offset by a decrease in weighted average DD&A expense rate resulting from our improved reserve quantities as of December 31, 2021.

The period-over-period change in DD&A expense related to crude oil and natural gas properties was primarily due to the following:

	Change Between	
	June 30, 2022 - September 30, 2022	**September 30, 2021 - September 30, 2022**
	(in millions)	
Increase (decrease) in production	$ 12.8	$ 94.7
Increase (decrease) in weighted average depreciation, depletion and amortization rates	1.6	(25.4)
Total increase (decrease) in DD&A expense related to crude oil and natural gas properties	$ 14.4	$ 69.3

The following table presents our per Boe DD&A expense rates for crude oil and natural gas properties for the periods presented:

	Three Months Ended		Nine Months Ended	
	September 30, 2022	June 30, 2022	September 30, 2022	September 30, 2021
	(per Boe)			
Operating Region/Area				
Wattenberg Field	$ 8.72	$ 8.52	$ 8.45	$ 9.04
Delaware Basin	9.86	10.68	10.30	9.54
Total weighted average DD&A expense rate	8.86	8.83	8.70	9.10

Interest Expense, net

Interest expense, net increased 6 percent to $18.6 million for the three months ended September 30, 2022 compared to $17.6 million for the three months ended June 30, 2022. The increase was primarily due to a $2.4 million increase relating to increased borrowings under our revolving credit facility in May 2022 to finance the acquisition of Great Western, partially offset by a $1.4 million increase in capitalized interest between periods.

Interest expense, net decreased 17 percent to $49.1 million for the nine months ended September 30, 2022 compared to $59.2 million for the nine months ended September 30, 2021. The decrease was primarily due to (i) an $8.6 million decrease from the expiration and redemption of our 2021 Convertible Notes in September 2021, (ii) a $4.7 million decrease from the full redemption of our 2025 Senior Notes in December 2021 and (iii) a $9.6 million decrease from a partial redemption of our 2024 Senior Notes in November 2021. These decreases were partially offset by a $13.2 million increase relating to increased borrowings under our revolving credit facility in May 2022 to finance the cash portion of the purchase price of the Great Western Acquisition.

Gain on Bargain Purchase

We recognized a $95.7 million gain on the bargain purchase of the Great Western Acquisition, net of related income taxes of $30.1 million, for the nine months ended September 30, 2022. For the three months ended September 30, 2022, we recognized a $4.6 million adjustment, net of related income tax of $1.4 million, to the initially recorded gain on bargain purchase of $100.3 million in the second quarter of 2022. For additional information, see *Note 2 - Business Combination* to our condensed consolidated financial statements included elsewhere in this report.

Provision for Income Taxes

Excluding the discrete gain on bargain purchase, we recorded income tax expense of $229.3 million and $128.0 million for the three months ended September 30, 2022 and June 30, 2022, respectively, resulting in an effective income tax rate of 22.2 percent and 18.5 percent provision on pre-tax income, respectively.

Excluding the discrete gain on bargain purchase, we recorded income tax expense of $358.5 million and $0.1 million for the nine months ended September 30, 2022 and September 30, 2021, respectively, resulting in an effective income tax rate of 21.2 percent and 0.1 percent provision on pre-tax income, respectively. The effective tax rates differ from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21 percent to pre-tax income due to state income taxes offset by the effect of the valuation allowance or changes in the valuation allowance against our deferred income tax assets.

The ultimate realization of deferred tax assets ("DTAs") is dependent upon the generation of future taxable income during the periods in which those temporary differences became deductible. At each reporting period, management considers the available taxes in carryback periods, the future reversals of existing taxable temporary differences, tax planning strategies and projected future taxable income in making this assessment. Our oil and gas property impairments and cumulative pre-tax losses were key considerations that led us to provide a valuation allowance against our DTAs beginning January 1, 2020, since we previously could not conclude that it is more likely than not that our DTAs will be fully realized in future periods.

As we previously disclosed in our 2021 Form 10-K, we maintained a valuation allowance on our net federal deferred tax assets and continued to do so until sufficient positive evidence existed to support a reversal of the allowance. In the second quarter of 2022, continued higher commodity prices increased our income, resulting in the reversal of objective negative evidence of cumulative loss in recent years, and we determined that we have sufficient positive evidence to release the valuation allowance. As a result, we released $22.5 million and $45.0 million of the valuation allowance against our deferred income tax assets and recognized a corresponding decrease to income tax expense in the three and nine months ended September 30, 2022, respectively. The remainder of the valuation allowance of $11.6 million will be recognized as a decrease to income taxes expense in the fourth quarter of 2022.

Given recent improvements in oil and gas prices and assumptions based on our current production forecasts, we estimate that we will incur significant cash federal and state income taxes in 2023.

In August 2022, the Inflation Reduction Act (“IRA”) was signed into law. The IRA includes implementation of a new alternative minimum tax, an excise tax on stock buybacks, and significant tax incentives for energy and climate initiatives, among other provisions. The alternative minimum tax and excise tax on stock buyback provisions are effective for tax years beginning after December 31, 2022. We continue to monitor updates to the IRA and the impact of the IRA to our financial position, results of operations and liquidity, however, we do not believe it will have a material impact on our stock buyback program or our financial position.

Net Income (Loss)/Adjusted Net Income (Loss)

The factors impacting a net income of $798.0 million and $662.4 million for the three months ended September 30, 2022 and June 30, 2022, respectively, and a net income of $1,428.4 million and $49.2 million for the nine months ended September 30, 2022 and September 30, 2021, respectively, are discussed above.

Adjusted net income, a non-U.S. GAAP financial measure, was $362.7 million and $502.1 million for the three months ended September 30, 2022 and June 30, 2022, respectively, and $1,152.7 million and $541.0 million for the nine months ended September 30, 2022 and September 30, 2021, respectively. With the exception of the tax-affected net change in fair value of unsettled commodity derivatives, when applicable, the same factors impacted adjusted net income (loss). See *Reconciliation of Non-U.S. GAAP Financial Measures* below for a more detailed discussion of these non-U.S. GAAP financial measures and a reconciliation of these measures to the most comparable U.S. GAAP measures.

Financial Condition, Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash and cash equivalents, cash flows from operating activities, unused borrowing capacity from our revolving credit facility, proceeds raised in debt and equity capital market transactions, and other sources, such as asset sales.

Our primary source of cash flows from operating activities is the sale of crude oil, natural gas and NGLs. Fluctuations in our operating cash flows are principally driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile and we manage a portion of this volatility through our use of commodity derivative instruments. We enter into commodity derivative instruments with maturities of no greater than five years from the date of the instrument. Our revolving credit facility imposes limits on the amount of our production we can hedge, and we may choose not to hedge the maximum amounts permitted. Therefore, we may still have fluctuations in our cash flows from operating activities due to the remaining non-hedged portion of our future production.

We may use our available liquidity for operating activities, capital investments, working capital requirements, acquisitions, capital returns and for general corporate purposes. We maintain a significant capital investment program to execute our development plans, which requires capital expenditures to be made in periods prior to initial production from newly developed wells. From time to time, these activities may result in a working capital deficit; however, we do not believe that our working capital deficit as of September 30, 2022 is an indication of a lack of liquidity. We had working capital deficits of $783.1 million as of September 30, 2022 and $461.5 million as of December 31, 2021. The increase in working capital deficit since December 31, 2021 primarily resulted from the Great Western Acquisition. We intend to continue to manage our liquidity position by a variety of means, including through the generation of cash flows from operations, investment in projects with favorable rates of return, protection of cash flows on a portion of our anticipated sales through the use of an active commodity derivative hedging program, utilization of the borrowing capacity under our revolving credit facility and, if warranted, capital markets transactions from time to time.

From time to time, we may seek to pay down, retire or repurchase our outstanding debt using cash or through exchanges of other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise.

Liquidity

Our cash and cash equivalents were $45.6 million at September 30, 2022 and availability under our revolving credit facility was $1,029.6 million, providing for a total liquidity position of $1,075.2 million as of September 30, 2022. The borrowing base is primarily based on the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests.

Our material short-term and long-term cash requirements consist primarily of capital expenditures, payments of contractual obligations, dividends, share repurchases and working capital obligations. If commodity prices continue to increase, our working capital requirements may increase due to higher operating costs and negative settlements on our outstanding commodity derivative contracts. Funding for these requirements may be provided by any combination of our capital resources previously outlined.

As a result of the Great Western Acquisition, we paid $361.2 million on Great Western’s behalf to pay and discharge Great Western’s 12% senior secured notes due 2025, inclusive of unpaid accrued interest and a premium for early termination. Additionally, we paid off Great Western’s secured credit facility totaling $235.8 million, inclusive of unpaid accrued interest. The termination of Great Western’s debt was funded through a combination of cash on hand and availability under our revolving credit facility.

Based on our current production forecast for 2022, we expect 2022 cash flows from operations, which are net of expected cash federal and state income taxes, to exceed our capital investments in crude oil and natural gas properties. In addition, based on our expected cash flows from operations, our cash and cash equivalents and availability under our revolving credit facility, we believe that we will have sufficient capital available to fund our planned activities through the 12-month period following the filing of this report. We also believe that we will have sufficient expected cash flows from operations to allow us to execute our capital return plan. Future repurchases of common stock or dividend payments will be subject to approval by our board of directors and will depend on our level of earnings, financial requirements, and other factors considered relevant by our board.

Our material cash requirements greater than twelve months from various contractual and other obligations include debt obligations and interest payments; commodity derivative contract liabilities; production taxes; operating and finance leases; asset retirement obligations; and firm transportation and processing agreements. There are no significant changes to our material cash requirements arising from contractual obligations since December 31, 2021, aside from the cash federal and state income taxes we anticipate starting in 2023, three-year drilling rig lease agreement entered in September 2022 and ordinary course contractual commitments acquired from Great Western.

In October 2022, as part of our credit facility 2022 semi-annual redetermination, our borrowing base increased from $3.0 billion to $3.5 billion driven by the reserves acquired from Great Western; however, we maintained our elected commitment amount of $1.5 billion. The revolving credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests on a quarterly basis. The financial tests, as defined per the revolving credit facility, include requirements (a) to maintain a minimum current ratio of 1.0:1.0 and (b) not exceed a maximum leverage ratio of 3.5:1.0. For purposes of the current ratio covenant, the revolving credit facility’s definition of total current assets, in addition to current assets as presented under U.S. GAAP, includes, among other things, unused commitments under the revolving credit facility. Additionally, the current ratio covenant calculation allows us to exclude the current portion of our long-term debt and other short-term loans from the U.S. GAAP total current liabilities amount. Accordingly, the existence of a working capital deficit under U.S. GAAP is not necessarily indicative of a violation of the current ratio covenant. At September 30, 2022, we were in compliance with all covenants in the revolving credit facility with a current ratio of 1.5:1.0 and a leverage ratio of 0.5:1.0.

We expect to remain in compliance with the covenants under our credit facility and our Senior Notes throughout the 12-month period following the filing of this report.

Cash Flows

Our cash flows from operating, investing and financing activities are as follows:

	Nine Months Ended September 30,	
	2022	2021
	(in thousands)	
Cash flows from operating activities	$ 2,084,791	$ 1,027,820
Cash flows from investing activities	(1,848,263)	(424,474)
Cash flows from financing activities	(216,578)	(506,047)
Net increase (decrease) in cash and cash equivalents	$ 19,950	$ 97,299

Operating Activities. Our net cash flows from operating activities are primarily impacted by commodity prices, production volumes, net settlements from our commodity derivative positions, operating costs, and general and administrative expense. Cash flows from operating activities increased by $1,057.0 million to $2,084.8 million during the nine months ended September 30, 2022 compared to $1,027.8 million during the nine months ended September 30, 2021. The increase between periods was primarily due to a $1,616.3 million increase in revenue from crude oil, natural gas and NGLs sales. This increase was partially offset by a $497.7 million increase in derivative settlement losses, a $149.2 million increase in production taxes, a $64.1 million increase in lease operating expense and the timing of receivable collections and vendor payments between periods.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $875.2 million to $1,934.7 million during the nine months ended September 30, 2022 from $1,059.5 million during the nine months ended September 30, 2021. The increase was primarily due to the factors mentioned above for changes in cash flows provided by operating activities, without regard to timing of cash payments and receipts of assets and liabilities. Adjusted free cash flow, a non-U.S. GAAP financial measure, increased by $553.5 million during the nine months ended September 30, 2022 to $1,163.0 million compared to $609.5 million during the nine months ended September 30, 2021. The increase between periods was primarily due to the increase in cash flows from operating activities, as discussed above, partially offset by an increase in capital investments in crude oil and natural gas properties as a result of our 2022 development plan and the Great Western Acquisition.

See *Reconciliation of Non-U.S. GAAP Financial Measures*, below, for a more detailed discussion of these non-U.S. GAAP financial measures and a reconciliation of these measures to the most comparable U.S. GAAP measures.

Investing Activities. As crude oil and natural gas production from a well declines rapidly in the first few years of production, we need to continue to commit significant amounts of capital in order to maintain and grow our production and replace our crude oil and natural reserves. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our revolving credit facility as the sources for funding our capital investments.

Cash flows from investing activities primarily consist of the acquisition, exploration and development of crude oil and natural gas properties, net of dispositions of crude oil and natural gas properties. Net cash used in investing activities of $1,848.3 million during the nine months ended September 30, 2022 was primarily due to $1,068.2 million related to the closing of the Great Western Acquisition as well as our drilling and completion activities of $773.7 million. Net cash used in investing activities of $424.5 million during the nine months ended September 30, 2021 was primarily related to our drilling and completion activities of $428.8 million, partially offset by $4.7 million in proceeds from the sale of certain properties and equipment.

Financing Activities. Net cash used in financing activities of $216.6 million during the nine months ended September 30, 2022 was primarily due to (i) net borrowings from our credit facility of $450.0 million to fund the cash portion of the purchase price of the Great Western Acquisition and to terminate Great Western's debt, (ii) the repurchase of 8.5 million shares of our common stock for $556.0 million pursuant to our stock repurchase program and (iii) dividend payments totaling $92.0 million. Repurchases of our common stock may extend through the end of 2023 based on current market conditions, although the board of directors could elect to suspend or terminate the program at any time, including if certain share price parameters are not achieved. As of September 30, 2022, $716.9 million out of the approved $1.25 billion remained available for repurchases under the program. Future repurchases of common stock or dividend payments will be subject to approval by our board of directors and depend on our level of earnings, financial requirements, and other factors considered relevant by our board.

Net cash used in financing activities of $506.0 million during the nine months ended September 30, 2021 was primarily due to net repayments on our credit facility of $168.0 million, redemption and retirement of our 2021 Convertible Notes for $200 million, the repurchase of 2.7 million shares of our common stock for $107.3 million pursuant to our stock repurchase program and dividend payments totaling $23.6 million.

Subsidiary Guarantors

PDC Permian, Inc., a Delaware corporation ("Permian"), and Pioneer Water Pipeline LLC, a Delaware limited liability company ("Pioneer" and together with "Permian", the "Guarantors"), each a wholly-owned subsidiary, guarantees our obligations under our 2024 Senior Notes and 2026 Senior Notes (collectively, the "Senior Notes"). Permian holds our assets located in the Delaware Basin. Pioneer holds certain water midstream assets located in the Wattenberg Basin. The Senior Notes are fully and unconditionally guaranteed on a joint and several basis by the Guarantors. The guarantees are subject to release in limited circumstances only upon the occurrence of certain customary conditions.

The indentures governing the Senior Notes contain customary restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (i) incur additional debt including under our revolving credit facility, (ii) make certain investments or pay dividends or distributions on our capital stock or purchase, redeem or retire capital stock, (iii) sell assets, including capital stock of our restricted subsidiaries, (iv) restrict the payment of dividends or other payments by restricted subsidiaries to us, (v) create liens that secure debt, (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company.

The following summarized subsidiary guarantor financial information has been prepared on the same basis of accounting as our condensed consolidated financial statements. Investments in subsidiaries are accounted for under the equity method.

	As of/Nine Months Ended September 30, 2022		As of/Year Ended December 31, 2021	
	Issuer	Guarantors	Issuer	Guarantor
	(in millions)			
Assets				
Current assets	$ 661.6	$ 66.4	$ 402.6	$ 56.0
Intercompany accounts receivable, guarantor subsidiary	—	289.0	—	40.8
Investment in guarantor subsidiary	1,767.2	—	1,767.2	—
Properties and equipment, net	6,117.5	1,009.8	3,875.0	939.9
Other non-current assets	165.6	7.2	58.5	4.8
Liabilities				
Current liabilities	$ 1,443.6	$ 67.4	$ 862.5	$ 57.6
Intercompany accounts payable	289.0	—	27.9	—
Long-term debt	1,393.5	—	942.1	—
Other non-current liabilities	977.2	165.0	392.3	172.0
Statement of Operations				
Crude oil, natural gas and NGLs sales	$ 2,778.1	$ 542.5	$ 2,163.1	$ 389.5
Commodity price risk management gain (loss), net	(363.3)	—	(701.5)	—
Total revenues	2,418.7	547.5	1,464.5	391.4
Production costs	868.2	213.7	892.4	189.0
Gross profit [(1)]	1,910.0	328.9	1,270.7	200.4
Impairment of properties and equipment	0.8	0.9	0.4	—
Net income (loss)	1,113.1	315.3	327.7	194.9

(1) *Gross profit is calculated as crude oil, natural gas and NGLs sales less production costs.*

Recent Accounting Pronouncements

There were no significant new accounting standards adopted or new accounting pronouncements that would have potential effect on us as of September 30, 2022.

Critical Accounting Policies and Estimates

The preparation of the accompanying condensed consolidated financial statements in conformity with U.S. GAAP required management to use judgment in making estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses.

There have been no significant changes to our critical accounting policies and estimates or in the underlying accounting assumptions and estimates used in these critical accounting policies from those disclosed in the consolidated financial statements and accompanying notes contained in our 2021 Form 10-K filed with the SEC on February 28, 2022.

Reconciliation of Non-U.S. GAAP Financial Measures

We use “adjusted cash flows from operations”, “adjusted free cash flow (deficit)”, “adjusted net income (loss)” and “adjusted EBITDAX”, non-U.S. GAAP financial measures, for internal management reporting, when evaluating period-to-period changes and, in some cases, in providing public guidance on possible future results. In addition, we believe these are measures of our fundamental business and can be useful to us, investors, lenders, and other parties in the evaluation of our performance relative to our peers and in assessing acquisition opportunities and capital expenditure projects. These supplemental measures are not measures of financial performance under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss) or cash flows from operations, investing or financing activities and should not be viewed as liquidity measures or indicators of cash flows reported in accordance with U.S. GAAP. The non-U.S. GAAP financial measures that we use may not be comparable to similarly titled measures reported by other companies. In the future, we may disclose different non-U.S. GAAP financial measures in order to help us and our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and to not rely on any single financial measure.

Adjusted cash flows from operations and adjusted free cash flow (deficit). We believe adjusted cash flows from operations can provide additional transparency into the drivers of trends in our operating cash flows, such as production, realized sales prices and operating costs, as it disregards the timing of settlement of operating assets and liabilities. We believe adjusted free cash flow (deficit) provides additional information that may be useful in an investor analysis of our ability to generate cash from operating activities from our existing oil and gas asset base to fund exploration and development activities and to return capital to stockholders in the period in which the related transactions occurred. We exclude from this measure cash receipts and expenditures related to acquisitions and divestitures of oil and gas properties and capital expenditures for other properties and equipment, which are not reflective of the cash generated or used by ongoing activities on our existing producing properties and, in the case of acquisitions and divestitures, may be evaluated separately in terms of their impact on our performance and liquidity. Adjusted free cash flow is a supplemental measure of liquidity and should not be viewed as a substitute for cash flows from operations because it excludes certain required cash expenditures. For example, we may have mandatory debt service requirements or other non-discretionary expenditures which are not deducted from the adjusted free cash flow measure.

We are unable to present a reconciliation of forward-looking adjusted cash flow because components of the calculation, including fluctuations in working capital accounts, are inherently unpredictable. Moreover, estimating the most directly comparable GAAP measure with the required precision necessary to provide a meaningful reconciliation is extremely difficult and could not be accomplished without unreasonable effort. We believe that forward-looking estimates of adjusted cash flow are important to investors because they assist in the analysis of our ability to generate cash from our operations.

Adjusted net income (loss). We believe that adjusted net income (loss) provides additional transparency into operating trends, such as production, realized sales prices, operating costs and net settlements on commodity derivative contracts, because it disregards changes in our net income (loss) from mark-to-market adjustments resulting from net changes in the fair value of our unsettled commodity derivative contracts, and these changes are not directly reflective of our operating performance.

Adjusted EBITDAX. We believe that adjusted EBITDAX provides additional transparency into operating trends because it reflects the financial performance of our assets without regard to financing methods, capital structure, accounting methods or historical cost basis. In addition, because adjusted EBITDAX excludes certain non-cash expenses, we believe it is not a measure of income, but rather a measure of our liquidity and ability to generate sufficient cash for exploration, development, and acquisitions and to service our debt obligations.

The following table presents a reconciliation of each of our non-U.S. GAAP financial measures to its most comparable U.S. GAAP measure for the periods presented:

	Three Months Ended		Nine Months Ended	
	September 30, 2022	June 30, 2022	September 30, 2022	September 30, 2021
	(in millions)			
Cash flows from operations to adjusted cash flows from operations and adjusted free cash flow:				
Net cash from operating activities	$ 848.4	$ 747.4	$ 2,084.8	$ 1,027.8
Changes in assets and liabilities	(147.1)	(52.7)	(150.1)	31.7
Adjusted cash flows from operations	701.3	694.7	1,934.7	1,059.5
Capital expenditures for development of crude oil and natural gas properties	(240.2)	(346.7)	(773.7)	(428.8)
Capital expenditures for midstream assets	(5.7)	(3.0)	(8.7)	—
Change in accounts payable related to capital expenditures for oil and gas development activities and midstream assets	(15.0)	58.8	10.7	(21.2)
Adjusted free cash flow	$ 440.4	$ 403.8	$ 1,163.0	$ 609.5
Net income (loss) to adjusted net income (loss):				
Net income (loss)	$ 798.0	$ 662.4	$ 1,428.4	$ 49.2
Loss (gain) on commodity derivative instruments	(306.7)	102.0	363.3	707.2
Net settlements on commodity derivative instruments	(252.8)	(298.7)	(713.1)	(215.4)
Tax effect of above adjustments (1)	124.2	36.4	74.1	—
Adjusted net income (loss)	$ 362.7	$ 502.1	$ 1,152.7	$ 541.0
Net income (loss) to adjusted EBITDAX:				
Net income (loss)	$ 798.0	$ 662.4	$ 1,428.4	$ 49.2
Loss (gain) on commodity derivative instruments	(306.7)	102.0	363.3	707.2
Net settlements on commodity derivative instruments	(252.8)	(298.7)	(713.1)	(215.4)
Non-cash stock-based compensation	7.2	7.2	20.0	17.3
Interest expense, net	18.6	17.6	49.1	59.2
Income tax expense (benefit)	229.3	128.0	358.5	0.1
Impairment of properties and equipment	0.2	0.5	1.6	0.3
Exploration, geologic and geophysical expense	11.8	0.3	12.4	0.9
Depreciation, depletion and amortization	205.6	191.1	547.7	478.6
Accretion of asset retirement obligations	3.5	3.4	9.8	9.2
Loss (gain) on sale of properties and equipment	(0.1)	0.5	0.3	(0.6)
Adjusted EBITDAX	$ 714.6	$ 814.3	$ 2,078.0	$ 1,106.0
Cash from operating activities to adjusted EBITDAX:				
Net cash from operating activities	$ 848.4	$ 747.4	$ 2,084.8	$ 1,027.8
Gain on bargain purchase	(4.6)	100.3	95.7	—
Interest expense, net	18.6	17.6	49.1	59.2
Amortization and write-off of debt discount, premium and issuance costs	(1.4)	(1.3)	(4.1)	(11.2)
Exploration, geologic and geophysical expense	0.3	0.3	0.9	0.9
Other	0.4	2.7	1.7	(2.4)
Changes in assets and liabilities	(147.1)	(52.7)	(150.1)	31.7
Adjusted EBITDAX	$ 714.6	$ 814.3	$ 2,078.0	$ 1,106.0

(1) Due to the full valuation allowance recorded against our net deferred tax assets, there is no tax effect for the nine months ended September 30, 2021.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rate risks, commodity price risk and credit risk. Recent inflationary trends and the possibility of a recession could impact each of these market risks. We have established risk management processes to monitor and manage these market risks.

Interest Rate Risk

Changes in interest rates affect the amount of interest we earn on our interest bearing cash, cash equivalents and restricted cash accounts and the interest we pay on borrowings under our revolving credit facility. Our 2024 Senior Notes and 2026 Senior Notes have fixed rates, and therefore near-term changes in interest rates do not expose us to risk of earnings or cash flow loss; however, near-term changes in interest rates may affect the fair value of our fixed-rate debt.

As of September 30, 2022, we had $450.0 million outstanding borrowings under our revolving credit facility. If market interest rates would have increased or decreased one percent, our interest expense for the nine months ended September 30, 2022 would have changed by approximately $3.3 million.

Commodity Price Risk

We are exposed to the potential risk of loss from adverse changes in the market price of crude oil, natural gas, natural gas basis and NGLs. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control. Pursuant to established policies and procedures, we manage a portion of the risks associated with these market fluctuations using commodity derivative instruments. These instruments help us predict with greater certainty the effective crude oil and natural gas prices we will receive for our hedged production. We believe that our commodity derivative policies and procedures are effective in achieving our risk management objectives.

As of September 30, 2022, we had a net liability derivative position of $336.8 million related to our commodity price risk derivatives. Based on a sensitivity analysis as of September 30, 2022, we estimate that a 10 percent increase in natural gas prices, crude oil prices and the propane portion of NGLs prices, inclusive of basis, over the entire period for which we have commodity derivatives in place, would have resulted in an increase in the fair value of our net derivative liabilities of $168.2 million, whereas a ten percent decrease in prices would have resulted in a decrease in fair value of our net derivative liabilities of $166.2 million. The potential increase in the fair value of our net derivative liabilities would be recorded in statements of operations as a loss. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure. When exposed to significant credit risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We monitor the creditworthiness of significant counterparties through our credit committee, which utilizes a number of qualitative and quantitative tools to assess credit risk and takes mitigative actions if deemed necessary. While we believe that our credit risk analysis and monitoring procedures are reasonable, no amount of analysis can assure performance by our counterparties.

We primarily use financial institutions which are lenders in our revolving credit facility as counterparties for our derivative financial instruments. Disruption in the credit markets, changes in commodity prices and other factors may have a significant adverse impact on a number of financial institutions. To date, we have had no material counterparty default losses from our commodity derivative financial instruments.

Our crude oil, natural gas and NGLs sales are concentrated with a few predominately large customers. This concentrates our credit risk exposure with a small number of large customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Disclosure of Limitations

Because the information above included only those exposures that existed at September 30, 2022, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time and interest rates and commodity prices at the time.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of September 30, 2022, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. Based on the results of this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2022.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

ITEM 1. LEGAL PROCEEDINGS

Additional information regarding our legal proceedings can be found in *Note 11 - Commitments and Contingencies* to our condensed consolidated financial statements included elsewhere in this report.

Environmental. Due to the nature of the oil and gas industry, we are exposed to environmental risks. We have various policies and procedures to minimize and mitigate the risks from environmental contamination. We conduct periodic reviews and simulated drills to identify changes in our environmental risk profile. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. Except as discussed herein, we are not aware of any material environmental claims existing as of September 30, 2022 which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown potential past non-compliance with environmental laws or other environmental liabilities will not be discovered on our properties. Accrued environmental liabilities are recorded in other accrued expenses on our condensed consolidated balance sheets.

Following a self-audit of final reclamation activities associated with site retirements, we formally disclosed identified deficiencies to the Colorado Oil and Gas Conservation Commission ("COGCC") in December 2019. To resolve the matter, in July of 2021, the COGCC and PDC jointly agreed to an Administrative Order by Consent ("AOC") which assessed penalties in the amount of approximately $500,000, with approximately $350,000 suspended pending PDC meeting certain conditions of the AOC. We are implementing programs to meet the requirements of the AOC and correct any identified deficiencies.

Commencing in early 2020, we conducted a comprehensive air quality compliance audit over the facilities acquired in the SRC Acquisition. Through the self-audit process, we identified certain deficiencies and disclosed them to the Colorado Department of Public Health and Environment ("CDPHE") and the U.S. Environmental Protection Agency ("EPA") in July 2021. We do not believe potential penalties and other expenditures associated with the deficiencies identified will have a material effect on our financial condition or results of operations, but such penalties may exceed $300,000.

On August 30, 2021 and November 1, 2021, the COGCC issued us a Notice of Alleged Violation ("NOAV") related to the timing of wellhead pressure test reporting for certain wells in the Wattenberg Field. Pursuant to the NOAV, we have performed a comprehensive audit of our wellhead pressure testing and reporting processes. We have updated our processes and will continue to monitor them for effectiveness and efficiency to mitigate against the possibility of the alleged violations occurring in the future. We do not anticipate a material effect on our financial condition or results of operations. However, the potential penalties may exceed $300,000.

On July 11, 2022, we received a Notice of Violation/Cease and Desist Order ("NOV") from the Colorado Department of Public Health and Environment ("CDPHE"), pursuant to a May 2021 Stormwater Permit Audit and subsequent Compliance Advisory, the latter received by Great Western Operating Company on July 25, 2021. Having acquired the subject assets on May 6, 2022, we are working with the CDPHE to ensure ongoing compliance and resolve the NOV. We do not anticipate potential penalties and other expenditures associated with the NOV will have a material effect on our financial condition or results of operations, but such penalties will likely exceed $300,000.

Clean Air Act Agreement and Related Consent Decree. We continue to implement the requirements of a consent decree entered into with the EPA and CDPHE in 2017. Per the terms of the agreement, we applied for termination in February 2022 and anticipate a response without any further comments or required actions from the EPA. Over the course of executing the consent decree requirements, we have identified certain immaterial deficiencies in our implementation. We report these immaterial deficiencies to the appropriate authorities and remediate them promptly. We do not believe that the penalties and expenditures associated with the consent decree will have a material effect on our financial condition or results of operations, but they may exceed $300,000.

Further, we could be the subject of other enforcement actions by regulatory authorities in the future relating to our past, present, or future operations.

ITEM 1A. RISK FACTORS

We face many risks. Risk factors that could adversely affect our business, operating results, and financial condition as well as the value of an investment in our common stock are described under Item 1A, *Risk Factors*, of our 2021 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

There have been no material changes from the risk factors previously disclosed in our 2021 Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table presents information about our purchases of our common stock during the three months ended September 30, 2022:

Period	Total Number of Shares Purchased (1) (2)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (1) *(in millions)*
July	866,538	$ 58.71	864,738	$ 927.3
August	2,187,393	63.38	2,187,240	788.7
September	1,153,214	62.22	1,153,214	716.9
Total third quarter 2022 purchases	4,207,145	62.10	4,205,192	716.9

(1) In 2019, our board of directors approved a program pursuant to which we may acquire shares of our common stock from time to time. At December 31, 2021, $187.3 million out of the approved $525 million remained available for repurchase under the stock repurchase program. In February 2022, our board of directors approved a new stock repurchase program that reset the total repurchase value to $1.25 billion, which we currently anticipate fully utilizing by December 31, 2023. The stock repurchase program does not require any specific number of shares to be acquired and can be modified or discontinued by our board of directors at any time.

(2) Purchases outside of the stock repurchase program represent shares withheld from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans. The withheld shares are not considered common stock repurchased under the stock repurchase program.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES - None.

ITEM 4. MINE SAFETY DISCLOSURES - Not applicable.

ITEM 5. OTHER INFORMATION - None.

ITEM 6. EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
22	Securities guaranteed by Guarantors.					X
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1*	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X
104	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)					X

* Furnished herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PDC Energy, Inc.
(Registrant)

Date: November 2, 2022

/s/ Barton Brookman
Barton Brookman
President and Chief Executive Officer
(principal executive officer)

/s/ R. Scott Meyers
R. Scott Meyers
Senior Vice President and Chief Financial Officer
(principal financial officer)

Exhibit No. 22

Securities Guaranteed by Subsidiary Guarantors

Guaranteed Security	Subsidiary Guarantors
6.125 % Senior Notes, due September 15, 2024	PDC Permian, Inc. Pioneer Water Pipeline, LLC
5.75% Senior Notes, due May 15, 2026	PDC Permian, Inc. Pioneer Water Pipeline, LLC

Exhibit 31.1

CERTIFICATIONS

I, Barton Brookman, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PDC Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2022

/s/ Barton Brookman

Barton Brookman
President and Chief Executive Officer
(principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, R. Scott Meyers, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PDC Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2022

/s/ R. Scott Meyers

R. Scott Meyers
Senior Vice President and Chief Financial Officer
(principal financial officer)

Exhibit 32.1

CERTIFICATION

In connection with the Quarterly Report of PDC Energy, Inc. (the "Company") on Form 10-Q for the period ended September 30, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned certify pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Barton Brookman	November 2, 2022
Barton Brookman President and Chief Executive Officer (principal executive officer)	
/s/ R. Scott Meyers	November 2, 2022
R. Scott Meyers Senior Vice President and Chief Financial Officer (principal financial officer)	