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

FORM 10-K

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

For the fiscal year ended December 31, 2021

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	Ticker Symbol	Name of each exchange on which registered
Common Stock, par value $0.01 per share	PDCE	NASDAQ Global Select Market

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes T No £

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes £ No T

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 T 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 T 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. £

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2021 was $4.5 billion (based on the closing price of $45.79 per share as of the last business day of the fiscal quarter ending June 30, 2021).

As of February 15, 2022, there were 96,329,829 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

We hereby incorporate by reference into this document the information required by Part III of this Form, which will appear in our definitive proxy statement filed pursuant to Regulation 14A for our 2022 Annual Meeting of Stockholders.

PDC ENERGY, INC.
2021 ANNUAL REPORT ON FORM 10-K
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PART I

REFERENCES TO THE REGISTRANT

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 our wholly-owned subsidiaries consolidated for the purposes of our financial statements.

GLOSSARY OF UNITS OF MEASUREMENTS AND INDUSTRY TERMS

Units of measurements and industry terms are defined in the Glossary of Units of Measurements and Industry Terms, included at the end of this report.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K 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, the pending acquisition of Great Western Petroleum, LLC (“Great Western”) and the effects thereof; the expected timing of the acquisition of Great Western and the possibility that the acquisition will not close; statements regarding future: production, costs and cash flows; impacts of Colorado political matters, including initiatives influencing our ability to continue to obtain permits; drilling locations, zones and growth opportunities; 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 potential return of capital to shareholders through buyback of shares and/or payments of dividends; ongoing compliance with our consent decree; expected impact from emission reduction initiatives; risk of our counterparties non-performance on derivative instruments; 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;
- 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 cost 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 our 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 for cash federal and state income taxes;
- our ability to retain or attract senior management and key technical employees;
- difficulties in integrating our operations as a result of any significant acquisitions, including the pending acquisition of Great Western, or acreage exchanges;
- a failure to complete the acquisition of Great Western or an unanticipated assumption of liabilities or other problems with the acquisition;
- civil unrest, terrorist attacks and cyber threats; and
- success of strategic plans, expectations and objectives for our future operations.

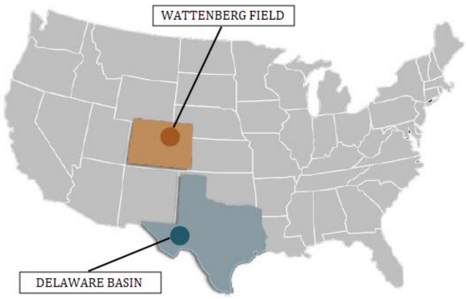
Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under Item 1A, *Risk Factors*, made in this report and our other filings with the U.S. Securities and Exchange Commission ("SEC") for further information on risks and uncertainties that 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.**

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

The Company

We are 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.

The following map presents the general locations of our development and production activities as of December 31, 2021:



The following table presents selected information regarding our business and results of operations as of and for the periods presented:

	Year Ended/As of December 31, 2021	Year Ended/As of December 31, 2020	Percent Change 2021-2020
	(production and reserves in MMBoe, dollars in millions)		
Wells:			
Gross productive wells	3,471	3,727	(7)%
Net productive wells	2,675	2,841	(6)%
Horizontal percentage	66 %	57 %	16 %
Gross operated wells turned-in-line	167	137	22 %
Net operated wells turned-in-line	160.4	129.5	24 %
Production:			
Wattenberg Field	61.9	57.5	8 %
Delaware Basin	9.4	10.8	(13)%
Total	71.3	68.4	4 %
Reserves:			
Proved reserves	814.2	731.1	11 %
Proved developed reserves percentage	49 %	44 %	11 %
Standardized measure	$ 7,908.2	$ 3,282.2	141 %
PV-10 [(1)]	$ 9,708.8	$ 3,454.6	181 %
Liquidity	1,514	1,400	8 %
Leverage ratio	0.6	1.7	(65)%

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(1) PV-10 is a non-U.S. GAAP financial measure. It is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure reported in accordance with U.S. generally accepted accounting principles ("U.S. GAAP"), but rather should be considered in addition to the standardized measure. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Reconciliation of Non-U.S. GAAP Financial Measures, for a definition of PV-10 and a reconciliation of our PV-10 value to the standardized measure included elsewhere in this report.

Pending Acquisition

On February 26, 2022, we entered into a definitive purchase agreement under which we will acquire Great Western for approximately $1.3 billion, inclusive of Great Western's net debt (the "Great Western Acquisition"). Great Western is an independent oil and gas company focused on the exploration, production and development of crude oil and natural gas in Colorado. We anticipate acquiring approximately 54,000 net acres in the Core Wattenberg and production of approximately 55,000 Boe per day. The purchase price of the Great Western Acquisition will consist of approximately 4.0 million shares of our common stock and approximately $543 million in cash, pursuant to the Membership Interest Purchase Agreement that we entered into with Great Western ("Acquisition Agreement"). We expect the Great Western Acquisition to be completed in the second quarter of 2022, subject to certain customary closing conditions.

Business Strategy and Key Strengths

Our long-term business strategy focuses on creating shareholder value by: (i) delivering attractive returns from our crude oil and natural gas properties with a keen focus on environmentally responsible and sustainable operations; (ii) maintaining financial strength; (iii) generating sustainable cash flows from operations in excess of our capital investments in crude oil and natural gas properties; and (iv) returning capital to shareholders. Our key strengths create long-term shareholder value through the following:

- ***Focus on generating sustainable cash flows from operations in excess of capital investments.*** We are focused on generating multi-year sustainable cash flows from operations in excess of our capital investments through managing capital spending and growth rates, adjusting the timing of completion of our inventory of drilled uncompleted wells

("DUCs"), utilizing commodity derivative instruments, focusing on margin improvement from reductions in our cost structure and increasing capital efficiency from technological innovation. Our adjusted free cash flows, a non-GAAP measure, is used as a measure of our ability to return capital to shareholders, reduce debt levels and maintain strong liquidity. In 2021, we generated cash flows from operations of $1.55 billion and adjusted free cash flows of $949.0 million.

- ***Strong financial position, absolute debt reduction and conservative total leverage targets***. We maintain a disciplined financial strategy that focuses on strong liquidity, low leverage ratios and an active commodity derivative program to help mitigate a portion of the risk associated with commodity price fluctuations. We believe that execution of this strategy will allow us to deliver strong corporate cash flows year-over-year, even through challenging commodity price environments. Through successful execution of our business plan, as of December 31, 2021, we reduced our indebtedness to below $1.0 billion, had total liquidity of $1.5 billion, and had a leverage ratio, as defined in our revolving line of credit facility agreement, of 0.6x. In addition, as of December 31, 2021, we had commodity derivative positions covering approximately 12.2 MMBbls, 8.3 MMBbls and 1.7 MMBbls of crude oil production for 2022, 2023 and 2024, respectively. As of the same date, we had hedged approximately 69,060 BBtu and 33,398 BBtu of natural gas production for 2022 and 2023, respectively.

- ***Sustainable return of capital to shareholders.*** We are committed to generating material and sustainable cash flows in a variety of commodity price environments, and to returning capital to our shareholders. In February 2021, we reinstated our Stock Repurchase Program and our board of directors approved a quarterly dividend program which commenced in May 2021. During 2021 we returned $244.9 million to shareholders through base dividends, share repurchases and a special dividend. For 2022 and beyond, our board of directors and management team are dedicated to a premier return of capital program with a quarterly base dividend and a return of approximately 60% or more of our remaining adjusted free cash flows, a non-U.S. GAAP financial measure, through stock repurchases and special dividends, as needed.

- ***Committed to meaningful and measurable environmental, social and governance ("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 newly created Environmental, Social, Governance and Nominating Committee (the "ESG&N Committee") at the board of directors and is applied at every level of our business.

    - ***Environment.*** Environmental protection is at the forefront of our ESG efforts. We view ourselves as playing a critical role in reducing greenhouse gas and methane emission intensities for environmentally responsible and sustainable operations. We are committed to the following goals:
        - Reduce greenhouse gas intensity by 60% from 2020 emissions by 2025 and 74% by 2030.
        - Reduce methane intensity by 50% from 2020 emissions by 2025 and 70% by 2030.
        - Eliminate routine flaring by 2025.

    - ***Social.*** We value our employees and their contribution to the work we do. Employees are our strongest asset and our success is directly related to the quality of our team. We have increased our focus on attracting and retaining a more diverse workforce through expanded internal recruitment efforts and partnerships with diversity-focused organizations within our communities. We are also dedicated to being an active and contributing member of the communities in which we operate. We value two-way communication and encourage community members to reach out to us directly with questions or concerns. Further, we have focused on establishing effective environmental, health and safety programs, trainings and policies that are intended to promote safe working practices for our employees and contractors and to help earn the trust and respect of land owners, regulatory agencies and public officials. This is an important part of our strategy in effectively operating in today's intensive regulatory climate.

    - ***Governance.*** We continue to commit to governance best practices and accountability to shareholders as we see this as a critical factor to our long-term success. We consistently seek board refreshment opportunities to ensure our board maintains a high level of diversity, including in thought and experience, and have recently added three new diverse board of director members. To further align with our accountability to our shareholders, in September 2021 we formalized our board oversight of ESG issues by incorporating ESG into the responsibilities of our Nominating and Governance Committee (the "N&G Committee"), which became the ESG&N Committee. In 2021 we added multiple ESG qualitative goals to our short-term incentive ("STI") program. This is in addition to our Total Recordable Incident Rate (“TRIR”), Preventable Vehicle Accident Rate (“PVAR”) and Spill Rate as quantitative performance and ESG metrics. The board of directors has also approved an additional quantitative performance metric for greenhouse gas and methane intensity reductions within our STI program, to further align management with our board of directors in our environmental goals.

- ***Significant operational control in our core areas.*** We have, and expect to continue to have, a substantial degree of operational control over our properties. As a result of successfully executing our strategy of acquisitions and acreage trades in our core areas of operations, we have built multiple concentrated acreage positions with high working interests that we believe will allow us to enhance the value of our assets and replenish our drilling inventory. We currently operate approximately 78 percent of all the wells in which we have an interest. This operational control allows us to better manage our drilling, production, operating and administrative costs and to leverage our technical expertise in our core operating areas. Our leaseholds that are held by production further enhance our operational control by providing us with additional flexibility on the timing of drilling of those locations.

- ***Project inventory in two premier crude oil, natural gas and NGL plays.*** We have a substantial multi-year inventory of high-quality horizontal drilling opportunities across two premier U.S. onshore basins: the Wattenberg Field in Weld County, Colorado and the Delaware Basin in Reeves County, Texas. Our portfolio has a proven record of delivering strong and repeatable economic returns and provides us the ability to allocate capital investments and manage risk as each basin has its own operating and competitive dynamic in terms of commodity price markets, service costs, takeaway capacity and regulatory and political considerations. We have a disciplined development program that seeks to expand our project inventory through testing new intervals and considering various spacing configurations. We believe our project inventory will allow us to achieve attractive rates of return and grow our proved reserves and production in a sustainable fashion. Such expected returns on drilling can vary well by well and are based upon many factors, including but not limited to commodity prices, well development and operating costs.

- ***Efficiency through technology and synergies from trades and acquisitions.*** Technological innovation has led to continued improvement in our drilling and completion times and is helping us achieve our emission reduction goals. We are continuously investing in new technology to improve the efficiency of our horizontal drilling and completion operations. For example, advanced completion equipment, including an anticipated electric fleet usage, and refinements in stage spacing, perforation clusters, and fluid and sand type and concentration continue to result in more efficient recoveries of crude oil and natural gas reserves and lower well emissions. Efficiencies are also driven by digital technologies such as artificial intelligence, machine learning and process automation technologies, which are utilized in our field and corporate operations. Additionally, acreage consolidation in both of our operating areas increases our ability to drill longer length lateral wells. Longer laterals allow us to develop our properties with a smaller number of wells and less truck traffic, with resulting benefits for our operations, the environment, and the communities in which we operate.

- ***Experienced management team with proven track record.*** We have a strong executive management team that has an average of 27 years of experience in the oil and gas industry. Collectively, this experience includes technical, operational, commercial, financial, legal and strategic aspects of the oil and gas industry. This team has a proven track record of executing value-added capital investment programs with a focus on financial discipline and improving on an already strong balance sheet, while growing production and proved reserves. Additionally, our team’s experience has helped us continue to achieve our strategic objectives through periods of commodity price volatility, cost inflation and other challenging operating environments.

Operating Areas

Wattenberg Field. In the Wattenberg Field, we have identified a gross operated inventory of approximately 1,800 horizontal locations that we expect to generate acceptable rates of return based on forward strip pricing, with an average lateral length of approximately 9,700 feet. Our inventory consists of approximately 145 gross operated DUCs, 235 approved permits, reflecting approximately 3.0 years of turn-in-line activity based on our current drilling plan, and 1,420 unpermitted locations. Our Wattenberg Field locations are subject to Oil and Gas Development Plans (“OGDP”) and Comprehensive Area Plans (“CAP”) regulated by Colorado Oil and Gas Conservation Commission (“COGCC”). We have two submissions in the review process with the COGCC for proposed wells in rural Weld County, one submitted for a multi-pad development plan including approximately 70 wells, and one submitted for a plan including approximately 450 wells. We anticipate a COGCC determination on both applications in 2022 or early 2023. The wells included in these applications represent our planned turn-in-line activity into 2027.

Our Wattenberg Field horizontal drilling locations have been substantially de-risked through multiple years of successful development in the field. We continue to analyze and test various wellbore spacing configurations in areas of the field that we believe have the potential to increase our gross operated inventory. Substantially all of our Wattenberg Field acreage is held by production. Wells in the Wattenberg Field typically have productive horizons at depths of approximately 6,500 to 7,500 feet below the surface. We continue to pursue various business development initiatives, with a focus on acreage exchanges or acquisitions, designed to increase our Wattenberg Field project inventory or to increase our ownership in our operated wells.

Delaware Basin. In the Delaware Basin, as a result of our completion activities and the performance of wells turned-in-line during 2021, we have developed a relaxed spacing program of approximately eight wells per undeveloped section equivalent and new operational techniques reflecting a gross operated economic inventory of approximately 65 horizontal locations, representing three to four years of inventory. Our inventory consists of approximately 20 gross operated DUCs that we expect to generate acceptable rates of return based on forward strip pricing, targeting the Wolfcamp A and Wolfcamp B zones. The average lateral length of these locations is approximately 10,200 feet. Wells in the Delaware Basin typically have productive horizons at depths of approximately 9,000 to 11,500 feet below the surface. In 2022, we are expanding our drilling program to include untested target zones that may be subject to a higher degree of uncertainty as well as innovative drilling techniques. If successful, we anticipate both initiatives will allow us to increase our field inventory. We also continue to pursue various business development initiatives, with a focus on acreage exchanges and joint development projects, designed to increase our Delaware Basin project inventory by establishing longer lateral drilling units capable of delivering attractive economic returns or to increase our ownership in our operated wells.

Oil and Gas Production and Operations

Proved Oil and Gas Reserves

The following table presents our proved reserve estimates as of the dates indicated:

	December 31, 2021		December 31, 2020		December 31, 2019
Proved reserves					
Crude oil and condensate *(MMBbls)*		214		212	197
Natural gas *(Bcf)*		2,160		1,901	1,558
NGLs *(MMBbls)*		240		203	154
Total proved reserves *(MMBoe)*		814		731	611
Proved developed reserves *(MMBoe)*		399		322	214
Standardized measure *(in millions)*	$	7,908	$	3,282	$ 3,310
Estimated undiscounted future net cash flows *(in millions)* (1)	$	13,872	$	5,633	$ 5,896
PV-10 (*in millions)* (2)	$	9,709	$	3,455	$ 3,837

(1) Amount represents aggregate undiscounted future net cash flows, before income taxes, of approximately $17.0 billion, $5.9 billion and $6.8 billion as of December 31, 2021, 2020 and 2019, respectively, less an internally-estimated undiscounted future income tax expense of approximately $3.1 billion, $0.3 billion and $0.9 billion, respectively.

(2) PV-10 is a non-U.S. GAAP financial measure. It is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure reported in accordance with U.S. GAAP, but rather should be considered in addition to the standardized measure. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Reconciliation of Non-U.S. GAAP Financial Measures, for a definition of PV-10 and a reconciliation of our PV-10 value to the standardized measure.

The additions to our proved reserves at December 31, 2021 compared to December 31, 2020 were primarily due to positive revisions resulting from our development activities and significant improvements in commodity prices during 2021, resulting in better economics and therefore increased quantities of reserves.

The additions to our proved reserves at December 31, 2020 as compared to December 31, 2019 were primarily due to the reserves acquired from our merger with SRC Energy, Inc. ("SRC Acquisition"), which were partially offset by downward revisions as a result of decreases in realized prices and revised drilling plans following the completion of the SRC Acquisition.

The following table presents our proved reserve estimates by category as of December 31, 2021:

Operating Region/Area	Crude Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Crude Oil Equivalent (MMBoe)	Percent
Proved developed					
Wattenberg Field	77	946	106	341	42 %
Delaware Basin	20	143	14	58	7 %
Total proved developed	97	1,089	120	399	49 %
Proved undeveloped					
Wattenberg Field	110	1,026	116	397	49 %
Delaware Basin	7	45	4	18	2 %
Total proved undeveloped	117	1,071	120	415	51 %
Total proved reserves					
Wattenberg Field	187	1,972	222	738	91 %
Delaware Basin	27	188	18	76	9 %
Total proved reserves	214	2,160	240	814	100 %

Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Positive impacts of these variables and assumptions may result in a longer economic productive life of a property or the recognition of more economically viable proved undeveloped ("PUD") reserves, while negative impacts of these variables and assumptions may result in corresponding negative impacts. All of our proved reserves are located in the United States.

Commodity Pricing. Per SEC rules, the pricing used to prepare the proved reserves is based on the unweighted arithmetic average of the first of the month prices for the preceding 12 months. The NYMEX prices used in preparing the reserves are then adjusted based on energy content, location and basis differentials and other marketing deductions to arrive at the net realized price.

	Average Benchmark Prices		
December 31,	**Crude Oil (per Bbl) (1)**	**Natural Gas (per MMBtu) (1)**	**NGLs (per Bbl) (2)**
2021	$ 66.56	$ 3.60	$ 66.56
2020	39.57	1.99	39.57
2019	55.69	2.58	55.69

(1) Our benchmark indexes for crude oil and natural gas are WTI and Henry Hub, respectively.
(2) For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes.

The netted back price used to estimate our reserves, by commodity, are presented below.

	Price Used to Estimate Reserves (1)		
December 31,	**Crude Oil (per Bbl)**	**Natural Gas (per MMBtu)**	**NGLs (per Bbl)**
2021	$ 65.37	$ 2.85	$ 24.96
2020	37.52	1.26	10.55
2019	52.63	1.50	12.21

(1) These prices are based on index prices and are net of basin differentials, transportation fees, contractual adjustments and Btu adjustments we experienced for the respective commodity.

Proved Reserves Sensitivity Analysis. We have performed an analysis of our proved reserve estimates as of December 31, 2021 to present sensitivity associated with a lower crude oil price as the value of crude oil influences the value of our proved reserves and PV-10 most significantly.

Replacing the 2021 NYMEX price for crude oil used in estimating our reported proved reserves with $60 and $45 as shown on the table below, and leaving all other parameters unchanged, results in changes to our estimated proved reserves as shown.

	Pricing Scenario - NYMEX					
	Crude Oil (per Bbl)	**Natural Gas (per MMBtu)**	**Proved Reserves (MMBoe)**	**% Change from December 31, 2021 Estimated Reserves**	**PV-10 (in Millions)**	**PV-10 % Change from December 31, 2021 Estimated Reserves**
2021 SEC Reserve Report (1)	$ 66.56	$ 3.60	814,188	—	$ 9,708.8	—
Alternate Price Scenario 1	$ 60.00	$ 3.60	809,928	(1)%	$ 8,651.6	(11)%
Alternate Price Scenario 2	$ 45.00	$ 3.60	796,618	(2)%	$ 6,239.7	(36)%

(1) These prices are the SEC NYMEX prices applied to the calculation of the PV-10 value. Such prices have been applied consistently in the alternate pricing scenario to include the impact of adjusting for deductions for any basin differentials, transportation fees, contractual adjustments and Btu adjustments we experienced for the relevant commodity.

Commodities and Standardized Measure. Reserve estimates involve judgments and reserves cannot be measured exactly. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geologic and geophysical data and economic changes. Neither the estimated future net cash flows nor the standardized measure of discounted future net cash flows ("standardized measure") is intended to represent the current market value of our proved reserves.

For additional information regarding our standardized measures, as well as other information regarding our proved reserves, see Supplemental Information- Crude Oil and Natural Gas Properties included in *Item 8. Financial Statements and Supplementary Data* provided with our consolidated financial statements included elsewhere in this report.

Preparation of Reserve Estimates

Our proved reserves estimates as of December 31, 2021 were based on evaluations prepared by our independent petroleum engineering consulting firms, Ryder Scott Company, L.P. ("Ryder Scott") and Netherland, Sewell & Associates, Inc. ("NSAI") (collectively, our "external engineers"). Our proved reserve estimates were prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the "FASB").

Controls Over Reserve Report Preparation. Inputs and major assumptions related to our proved reserves are reviewed annually by an internal team composed of reservoir engineers, geologists, land and management for adherence to SEC guidelines through a detailed review of land and accounting records, available geological and reservoir data and production performance data. The internal team compiles the reviewed data and forwards the applicable data to our external engineers.

Annually, the Director of Reservoir Engineering & Technology reviews the reserves to ensure all the necessary significant inputs and steps are completed within our reserve process. After final approval from the Director of Reservoir Engineering & Technology, the results are presented to senior management and to our board of directors for their review.

Together, these internal controls are designed to promote a comprehensive, objective, and accurate reserves estimation process. As an additional confirmation of the reasonableness of our internal estimates, Ryder Scott and NSAI performed an independent evaluation of our estimated proved reserves in the Wattenberg Field and Delaware Basin, respectively, as of December 31, 2021.

When preparing our reserve estimates, our external engineers do not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, production volumes, well test data, historical costs of operations and development, product prices or any agreements relating to current and future operations of properties or sales of production. Our external engineers prepare estimates of our reserves in conjunction with an ongoing review by our engineers. A final comparison of data is performed to ensure that the reserve estimates are complete, determined pursuant to acceptable industry methods and with a level of detail we deem appropriate. The final estimated reserve reports are prepared by our external engineers and reviewed by our engineering staff and management prior to issuance by those firms.

In determining our proved reserves estimates, we used a combination of performance methods, including decline curve analysis and other computational methods, offset analogies and seismic data and interpretation. All of our proved undeveloped reserves conform to the SEC five-year rule requirement as all proved undeveloped locations are scheduled, according to an adopted development plan, to be drilled within five years of the location's initial booking date.

Qualifications of Responsible Technical Persons. The professional qualifications of our lead engineer primarily responsible for overseeing the preparation of our reserve estimates, as defined in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information as promulgated by the Society of Petroleum Engineers, qualifies this individual as a Reserve Estimator. This person holds a Masters Degree in Petroleum Engineering from the Colorado School of Mines and a Bachelors Degree in Geology from the University of Colorado and has over 21 years of oil and gas experience.

Letters which identify the professional qualifications of the individuals at Ryder Scott and NSAI who are responsible for overseeing the preparation of our reserve estimates as of December 31, 2021 have been filed as Exhibits 99.1 and 99.2 to this report.

Production, Prices and Costs

Production and operating data for the years ended December 31, 2021, 2020 and 2019 is included in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* included elsewhere in this report.

Productive Wells

The following table presents our productive wells by operating area as of December 31, 2021:

	Crude Oil		**Natural Gas**		**Total**	
Operating Region/Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Wattenberg Field	2,205	1,586.5	1,129	977.0	3,334	2,563.5
Delaware Basin	52	37.9	85	73.4	137	111.3
Total productive wells	2,257	1,624.4	1,214	1,050.4	3,471	2,674.8

Productive wells consist of producing wells and wells capable of production, including crude oil wells awaiting pipeline connections to commence deliveries, natural gas wells awaiting connection to production facilities and shut-in wells.

Developed and Undeveloped Acreage

The following table presents our developed and undeveloped lease acreage as of December 31, 2021:

	Developed		**Undeveloped**		**Total**	
Operating Region/Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Wattenberg Field	166,131	154,726	68,200	63,488	234,331	218,214
Delaware Basin	27,627	25,316	905	343	28,532	25,659
Total acreage	193,758	180,042	69,105	63,831	262,863	243,873

Developed lease acreage are acres spaced or assigned to productive wells and do not include undrilled acreage held by production under the terms of the lease. Large portions of the acreage that are considered developed under SEC guidelines are developed with vertical wells or horizontal wells that are in a single horizon. We believe much of this acreage has significant remaining development potential in one or more intervals with horizontal wells. Undeveloped acreage represents acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. However, substantially all of our undeveloped acreage in the Wattenberg Field and Delaware Basin is related to leaseholds that are held by production and therefore are not at risk of expiration or delay rental payments.

Our Wattenberg Field leaseholds at risk to expire in 2022, 2023 and 2024 are not material. In the Delaware Basin, the majority of the drilling obligations or continuous drilling clauses associated with the asset have been met. Our Delaware Basin leaseholds at risk to expire in 2022, 2023 and 2024 are not material. See *Item 1A. Risk Factors - Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in substantial lease renewal costs or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.*

Drilling Results

The following tables set forth a summary of our developmental and exploratory well drilling results for the periods presented. Productive wells consist of wells that were turned-in-line and commenced production during the period, regardless of when drilling was initiated. 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 as of the date shown. We utilize pad drilling operations, where multiple wells are developed from the same well pad, in both the Wattenberg Field and Delaware Basin. Because we may operate multiple drilling rigs in each operating area, we expect to have in-process wells at any given time. Wells may be in-process for up two years.

	Operated Development and Exploratory Well Drilling Activity As of and For the Year Ended December 31,					
	2021		**2020**		**2019**	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Wattenberg Field	149	143.0	124	116.5	114	105.1
Delaware Basin	16	15.5	13	13.0	21	20.1
Total development wells	165	158.5	137	129.5	135	125.2
In-Process Development Wells						
Wattenberg Field	143	133.0	214	201.8	145	135.0
Delaware Basin	21	20.6	18	17.2	26	25.3
Total in-process wells	164	153.6	232	219.0	171	160.3
Exploratory Wells - Productive						
Delaware Basin	2	1.9	2	2.0	2	2.0
In-Process Exploratory Wells						
Delaware Basin	—	—	2	1.9	4	3.9

There were no exploratory drilling activities in the Wattenberg Field during 2021, 2020 and 2019. Additionally, we did not have any dry wells during the same periods in either operating region.

Title to Properties

We believe that we hold good and defensible leasehold title to substantially all of our crude oil and natural gas properties, in accordance with standards generally accepted in the industry. A preliminary title examination is typically conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and remedial curative work is performed, as necessary, with respect to discovered defects which we deem to be significant, in order to procure division order title opinions. Title examinations have been performed with respect to substantially all of our producing properties.

The properties we own are subject to royalty, overriding royalty and other outstanding interests. The properties may also be subject to additional burdens, liens or encumbrances customary in the industry, including items such as operating agreements, current taxes, development obligations under crude oil and natural gas leases, farm-out agreements and other restrictions. We do not believe that any of these burdens will materially interfere with our use of the properties.

A significant portion of our crude oil and natural gas properties have been mortgaged or pledged as security for amounts borrowed under our revolving credit facility.

Offices

As of December 31, 2021, we leased corporate space in 1775 Sherman Street, Suite 3000, Denver, Colorado, where our corporate headquarters is located. We also maintain offices in Evans, Colorado and Midland, Texas. We sold our office building we owned in Bridgeport, West Virginia in March 2021. In January 2022, we entered into a long-term lease agreement for an office space located in Denver, Colorado.

Significant Customers

We sell our crude oil and natural gas production to marketers and other purchasers which have access to pipeline facilities. In areas where there is no practical access to pipelines, crude oil is transported to storage facilities by trucks owned or otherwise arranged by the marketers or purchasers. The majority of our crude oil and natural gas production is transported through pipelines.

We made sales to three customers that each contributed to 10 percent or more of our 2021 total crude oil, natural gas and NGLs revenues. However, given the liquidity in the market for the sale of hydrocarbons, we believe that the loss of any single purchaser, or the aggregate loss of several purchasers, could be managed by selling to alternative purchasers.

Seasonality of Business

Weather conditions affect the demand for and prices of crude oil and natural gas. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of our annual results.

Delivery Commitments

Certain of our firm sales agreements for crude oil include delivery commitments. We believe our current production and reserves are sufficient to fulfill these delivery commitments. See *Note 13 - Commitments and Contingencies* in *Item 8. Financial Statements and Supplementary Data* for more information.

Governmental Regulation

The U.S. crude oil and natural gas industry is extensively regulated at the federal, state and local levels. The following is a summary of certain laws, rules and regulations currently in force that apply to us. The regulatory environment in which we operate changes frequently and we cannot predict the timing or nature of such changes or their effects on us.

Regulation of Crude Oil and Natural Gas Exploration and Production. Our exploration and production activities are subject to a variety of rules and regulations concerning drilling permits, location, spacing and density of wells, water discharge and disposal, prevention of waste, bonding requirements, surface use and restoration, public health and environmental protection and well plugging and abandonment. The primary state-level regulatory authority regarding these matters in Colorado is the COGCC and in Texas is the Texas Railroad Commission. Prior to preparing a surface location and commencing drilling operations on a well, we must procure permits and/or approvals for the various stages of the drilling process from the relevant state and local agencies. In addition, our operations must comply with rules governing the size of drilling and spacing units or proration units and the unitization or pooling of lands and leases. Some states, such as Colorado, allow the forced pooling or integration of tracts to facilitate exploration while other states, such as Texas, rely primarily or exclusively on voluntary pooling of lands and leases.

In states such as Texas where pooling is primarily or exclusively voluntary, it may be more difficult to form units and therefore to drill and develop our leases in circumstances where we do not own all of the leases in the proposed unit. These risks also exist in Colorado, where the COGCC has imposed limits on forced pooling. State laws may also prohibit the venting or flaring of natural gas, which may impact rates of production of crude oil and natural gas from our wells. Leases covering state or federal lands often include additional laws, regulations and conditions which can limit the location, timing and number of wells we can drill and impose other requirements on our operations, all of which can increase our costs.

Regulation of Transportation of Commodities. We move natural gas through pipelines owned by other entities and sell natural gas to other entities that also utilize common carrier pipeline facilities. Natural gas pipeline interstate transmission and storage activities are subject to regulation by the Federal Energy Regulatory Commission (“FERC”) under the Natural Gas Act of 1938 (“NGA”) and under the Natural Gas Policy Act of 1978 (“NGPA”). Rates and charges for the transportation of natural gas in interstate commerce, and the extension, enlargement or abandonment of jurisdictional facilities, among other things, are subject to regulation.

In addition, the Energy Policy Act of 2005 (the “EPAct 2005”) prohibits “any entity” from using any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or the purchase or sale of transportation services subject to regulation by FERC. The EPAct 2005 provides FERC with substantial enforcement authority to prohibit such manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC Order 704 requires that any market participant, including natural gas producers, gatherers and marketers, that engaged in wholesale sales or purchases of natural gas that equaled or exceeded 2.2 MMBtus of physical natural gas in the previous calendar year to report to FERC the aggregate volumes of natural gas produced or sold at wholesale in such calendar year. Order 704 applies only to those transactions that utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the market participant to determine which individual transactions are to be reported under the guidance of Order 704. Additional information that must be reported includes whether the price in the relevant transaction was reported to any index publisher, and if so, whether such reporting complied with FERC’s policy statement on price reporting. To the extent that we engage in wholesale sales or purchases of natural gas that equal or exceed 2.2 MMBtus of physical natural gas in a calendar year pursuant to transactions utilizing, contributing or having the potential to contribute to the formation of price indices, we may be subject to the reporting requirements of Order 704.

Gathering is exempt from regulation under the NGA, thus allowing gatherers to charge negotiated rates. Gathering lines are, however, subject to state regulation, which includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and rate regulation on a complaint basis. We own certain pipeline facilities in the Delaware Basin that we believe are exempt from regulation under the NGA as “gathering facilities”, but which may in some cases be subject to state regulation.

Although FERC has set forth a general test to determine whether facilities are exempt from regulation under the NGA as “gathering” facilities, FERC’s determinations as to the classification of facilities are performed on a case-by-case basis. With respect to facilities owned by third parties and on which we move natural gas, to the extent that FERC subsequently issues an order reclassifying facilities previously thought to be subject to FERC jurisdiction as non-jurisdictional gathering facilities, and depending on the scope of that decision, our costs of moving natural gas to the point of sale may be increased. Further, to the extent that FERC issues an order reclassifying facilities that we own that were previously thought to be non-jurisdictional gathering facilities as subject to FERC jurisdiction, we could be subject to additional regulatory requirements under the NGA and the NGPA.

Transportation and safety of natural gas is also subject to regulation by the U.S. Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration (“PHMSA”), under the Natural Gas Pipeline Safety Act of 1968, as amended, which imposes safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the “PIPES Act 2006”), and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the “PIPES Act 2011”). We own certain pipeline facilities in the Delaware Basin that are subject to regulation under PHMSA.

In addition to natural gas, we move crude oil, condensate and natural gas liquids (collectively, “liquids”) through pipelines owned by other entities and sell such liquids to other entities that also utilize pipeline facilities that may be subject to regulation by FERC. FERC regulates the rates and terms and conditions of service for the interstate transportation of liquids under the Interstate Commerce Act, as it existed on October 1, 1977 (the “ICA”), and the rules and regulations promulgated thereunder. This includes movements of liquids through any pipelines, including those located solely within one state, that are providing part of the continuous movement of such liquids in interstate commerce for a shipper. The ICA requires that pipelines providing jurisdictional movements maintain a tariff on file with FERC, setting forth established rates and the rules and regulations governing transportation service, which must be “just and reasonable”. The ICA also requires that services be provided in a manner that is not unduly discriminatory or unduly preferential; in some cases, this may result in the proration of capacity among shippers in an equitable manner.

The intrastate transportation of liquids is subject to regulation by state regulatory commissions, which in some cases require the provision of intrastate transportation on a nondiscriminatory basis and the prorationing of capacity on such pipelines under policies set forth in published tariffs. These state-level regulations may also impose certain limitations on the rates that the pipeline owner may charge for transportation.

Transportation of liquids by pipeline is subject to regulation by PHMSA pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as well as the PIPES Act 2006 and the PIPES Act 2011, which govern the design, installation, testing, construction, operation, replacement and management of liquids pipeline facilities. Liquids that are transported by rail may also be subject to additional regulation by PHMSA.

The availability, terms and cost of transportation affect the amounts we receive for our commodities. Historically, producers were able to flow supplies into interstate pipelines on an interruptible basis; however, recently we have seen an increased need to acquire firm transportation on pipelines in order to avoid curtailments or shut-in gas, which could adversely affect cash flows from the affected area.

Democratic control of the House, Senate and White House could lead to increased regulatory oversight and increased regulation and legislation, particularly around oil and gas development on federal lands, climate impacts and taxes.

Environmental Matters

Our operations are subject to numerous laws and regulations relating to environmental protection. These laws and regulations change frequently, and the effect of these changes is often to impose additional costs or other restrictions on our operations. We cannot predict the occurrence, timing, nature or effect of these changes. We also operate under a number of environmental permits and authorizations. The issuing agencies may take the position that some or all of these permits and authorizations are subject to modification, suspension, or revocation under certain circumstances, but any such action would have to comply with applicable procedures and requirements.

Hazardous Substances and Wastes

We generate wastes that may be subject to the Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The U.S. Environmental Protection Agency ("EPA") and various state agencies have adopted requirements that limit the approved disposal methods for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by our operations that are currently exempt from treatment as "hazardous wastes" may in the future be designated as hazardous wastes, and therefore may subject us to more rigorous and costly operating and disposal requirements. In April 2019, the EPA, pursuant to a consent decree between the EPA and a coalition of environmental groups and a related review of RCRA regulations, determined that revision of the regulations is not necessary. The EPA indicated that it will continue to work with states and other organizations to identify areas for continued improvement and to address emerging issues to ensure that exploration, development and production wastes continue to be managed in a manner that is protective of human health and the environment. Environmental groups, however, expressed dissatisfaction with the EPA's decision and will likely continue to press the issue at the federal and state levels.

We currently own or lease numerous properties that have been used for the exploration and production of crude oil and natural gas for many years. If hydrocarbons or other wastes have been disposed of or released on or under the properties that we own or lease or on or under locations where such wastes have been taken for disposal by us or prior owners or operators of such properties, we could be subject to liability under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), RCRA and analogous state laws, as well as state laws governing the management of crude oil and natural gas wastes. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of, transported or arranged for the disposal of the hazardous substances found at the site. Parties who are or were responsible for release of hazardous substances under CERCLA may be subject to full liability for the costs of cleaning up the hazardous substances that have been released into the environment or remediation to prevent future contamination and for damages to natural resources. In addition, under state laws, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Hydraulic Fracturing

Hydraulic fracturing is commonly used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. We consistently utilize hydraulic fracturing in our crude oil and natural gas development programs. The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations which are held open by the grains of sand, enabling the crude oil or natural gas to more easily flow to the wellbore. The process is generally subject to regulation by state oil and gas commissions, but is also the subject of various other regulatory initiatives at the federal, state and local levels.

Local Regulation

Various local and municipal bodies in each of the states in which we operate have sought to impose prohibitions, moratoria and other restrictions on hydraulic fracturing activities. In Colorado, Senate Bill 19-181 ("SB 19-181") authorizes governmental authorities to regulate the siting and surface impacts of oil and gas development. We primarily operate in the rural areas of the core Wattenberg Field in Weld County, a jurisdiction in which there has historically been significant support for the oil and gas industry. In Texas, legislation enacted in 2015 generally prohibits political subdivisions from banning, limiting or otherwise regulating oil and gas operations. See *Item 1A. Risk Factors-Risks Relating to Our Business and the Industry-Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us.*

State Regulation

The states in which we currently operate have adopted or may adopt laws and regulations that impose or could impose, among other requirements, more stringent permitting processes and increased environmental protection and monitoring.

SB 19-181 changed the mission of the COGCC from fostering responsible and balanced development to regulating development to protect public health and the environment and directed the COGCC to undertake rulemaking on various operational matters. Pursuant to this direction, the COGCC conducted a series of rulemaking hearings during 2020 which resulted in updated regulatory and permitting requirements, including siting requirements. The new requirements prohibit the siting of locations within 2,000 feet of a school facility or child-care center. A similar 2,000-foot setback requirement applies to residential and high occupancy building units, but there are "off ramps" allowing oil and gas operators to site their drill pads as close as 500 feet from building units in certain circumstances.

In late July 2020, Governor Polis authored an op-ed stating that both industry and mainstream environmental groups have communicated a willingness to work together to prevent ballot initiatives in 2022. As part of that agreement, Governor Polis stated that he would "actively oppose" ballot initiatives around the oil and gas industry and acknowledged the importance of regulatory certainty.

It is nevertheless possible that future ballot initiatives will be proposed that would dramatically limit the areas of the state in which drilling would be permitted to occur. See *Item 1A. Risk Factors-Risks Relating to Our Business and the Industry-Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us.*

Federal Regulation

The U.S. Department of the Interior, through the Bureau of Land Management (the "BLM"), finalized a rule in 2015 requiring the disclosure of chemicals used, mandating well integrity measures and imposing other requirements relating to hydraulic fracturing on federal lands. The BLM rescinded the rule in December 2017. The BLM's rescission of the rule was challenged in the United States District Court for the Northern District of California and in March 2020 the court issued a ruling upholding BLM's rescission of the rule. That court ruling is currently subject to an appeal.

Private Lawsuits

Lawsuits have been filed against other operators in several states, including Colorado, alleging contamination of drinking water as a result of hydraulic fracturing activities.

Greenhouse Gases

The EPA has published findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because such emissions are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings provide the basis for the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. In June 2010, the EPA began regulating GHG emissions from stationary sources.

In the past, Congress has considered proposed legislation to reduce emissions of GHGs. To date, Congress has not adopted any such significant legislation, but may do so in the future. In November 2021, the U.S. House of Representatives passed H.R.5376, section 30114 of which would amend the Clean Air Act to impose a fee of $1,500 per ton of methane emitted above specified thresholds from onshore petroleum and natural gas production facilities, natural gas processing facilities, natural gas transmission and compression facilities, and onshore petroleum and natural gas gathering and boosting facilities, among other facilities. The U.S. Senate is currently considering H.R. 5376 and may adopt, modify, or eliminate the methane fee.

In addition, many states and regions have taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Since 2014, Colorado has engaged in multiple rulemakings to adopt significant additional rules regulating methane emissions from the oil and gas sector, and Colorado is expected to continue these efforts over the next several years.

The Obama administration reached an agreement during the December 2015 United Nations climate change conference in Paris pursuant to which the U.S. initially pledged to make a 26 percent to 28 percent reduction in its GHG emissions by 2025 against a 2005 baseline and committed to periodically update this pledge every five years starting in 2020 (the "Paris Agreement"). In April 2021, President Biden announced that the United States would aim to cut its greenhouse gas emissions 50 percent to 52 percent below 2005 levels by 2030.

Regulation of methane and other GHG emissions associated with oil and natural gas production could impose significant requirements and costs on our operations. See our GHG emission reduction goals included in *Items 1. and 2. Business and Properties* included elsewhere in this report.

Air Quality

Our operations are subject to the Clean Air Act (The "CAA") and comparable state and local requirements. The CAA contains provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and state governments continue to develop regulations to implement these requirements. We may be required to make certain capital investments in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. See the footnote titled *Commitments and Contingencies - Litigation and Legal Items* to our consolidated financial statements included elsewhere in this report for further information regarding the Clean Air Act Section 114 Information Request that we received from the EPA.

In June 2016, the EPA implemented new requirements focused on achieving additional methane and volatile organic compound reductions from the oil and natural gas industry. The rules imposed, among other things, new requirements for leak detection and repair, control requirements for oil well completions, replacement of certain pneumatic pumps and controllers and additional control requirements for gathering, boosting and compressor stations. In September 2018, the EPA proposed revisions to the 2016 rules. The proposed amendments address certain technical issues raised in administrative petitions and include proposed changes to, among other things, the frequency of monitoring for fugitive emissions at well sites and compressor stations. In September 2020, the EPA issued a new rule which amended the 2016 requirements. In this rule, the EPA removed all sources in the transmission and storage segment of the oil and natural gas industry from regulation. The rule also rescinded the methane requirements in the 2016 regulations and loosened monitoring and repair regulations aimed at preventing methane leaks. On June 30, 2021, however, President Biden signed into law a joint Congressional resolution disapproving and invalidating much of the 2020 rule amendments under the prior Administration, including the 2020 rule's rescission of the methane requirements. On November 15, 2021, EPA published a proposed rule that would update and expand existing requirements for the oil and gas industry, as well as creating significant new requirements and standards for new, modified, and existing oil and gas facilities. The proposed new requirements would include, for example, new standards and emission limitations applicable to storage vessels, well liquids unloading, pneumatic controllers, and flaring of natural gas at both new and existing facilities. The proposed rules for new and modified facilities are estimated to be finalized by the end of 2022, while any standards finalized for existing facilities will require further state rulemaking actions over the next several years before they become applicable and effective.

In November 2016, the BLM finalized rules to further regulate venting, flaring and leaks during oil and natural gas production activities on onshore federal and Indian leases (the “2016 Rule”). The 2016 Rule required additional controls and impose new emissions and other standards on certain operations on applicable leases, including committed state or private tracts in a federally approved unit or communitized agreement that drains federal minerals. In September 2018, the BLM published a final rule that revised the 2016 Rule (the “2018 Revised Rule”). The 2018 Revised Rule, among other things, rescinded the 2016 Rule requirements related to waste-minimization plans, gas-capture percentages, well drilling, well completion and related operations, pneumatic controllers, pneumatic diaphragm pumps, storage vessels and leak detection and repair. The 2018 Revised Rule also revised provisions related to venting and flaring. Environmental groups and the States of California and New Mexico filed challenges to the 2018 rule in the United States District Court for the Northern District of California, and in July 2020, the United States District Court for the Northern District of California vacated the BLM’s 2018 Revised Rule. However, in October 2020, the United States District Court for the District of Wyoming issued a ruling vacating the 2016 Rule, holding that the BLM exceeded its statutory authorities and acted arbitrarily. Both rulings have been appealed. The Spring 2021 Unified Agenda of Regulatory and Deregulatory Actions, published by the Office of Management and Budget’s Office of Information and Regulatory Affairs, identified a potential proposal by the BLM to update its existing rules governing the venting and flaring of natural gas (methane) from onshore Federal and Indian oil and gas leases. The BLM has not yet published such a proposed rule.

In 2019, the EPA increased the state of Colorado’s non-attainment ozone classification for the Denver Metro North Front Range Ozone Eight-Hour Non-Attainment (“Denver Metro/North Front Range NAA”) area from “moderate” to “serious” under the 2008 national ambient air quality standard (“NAAQS”). This increase in non-attainment status to “serious” triggered significant additional obligations for the state under the CAA and resulted in Colorado adopting new and more stringent air quality control requirements in December 2020 that are applicable to our operations. Based on current air quality monitoring data, it is expected that the Denver Metro/North Front Range NAA will be further “bumped-up” to “severe” status in 2022. This will trigger additional obligations for the state under the CAA and will result in new and more stringent air quality permitting and control requirements, which may in turn result in significant costs and delays in obtaining necessary permits applicable to our operations.

SB 19-181 also requires, among other things, that the Air Quality Control Commission (“AQCC”) adopt additional rules to minimize emissions of methane and other hydrocarbons and nitrogen oxides from the entire oil and gas fuel cycle. The AQCC has undertaken a multi-year rulemaking process to implement the requirements of SB 19-181, including a rulemaking to require continuous emission monitoring equipment at oil and gas facilities. Between December 2019 and December 2020, the AQCC completed several rulemakings as a result of SB 19-181, adopting significant additional and new emission control requirements applicable to oil and gas operations, including, for example, hydrocarbon liquids unloading control requirements, increased LDAR frequencies for facilities in certain proximity to occupied areas, and emission control requirements for certain large natural gas fired engines. The AQCC conducted an additional rulemaking in December 2021 related to SB 19-181, which is discussed further below.

Additionally, in response to HB 19-1261, which established statewide greenhouse gas reduction targets, Colorado, on September 30, 2020, released a public comment draft of its Greenhouse Gas Pollution Reduction Roadmap, which details early action steps the state can take toward meeting the near-term goals of reducing greenhouse gas (“GHG”) pollution by 26% by 2025 and 50% by 2030 from 2005 levels. On October 23, 2020, the AQCC issued the Resolution to Ensure Greenhouse Gas Reduction Goals Are Met in support of the roadmap, which estimates emission reductions needed from the oil and gas sector of 36% by 2025 and 50% by 2030. To meet these targets, as well as to address other air quality and environmental justice issues, the AQCC held a hearing in December 2021 and voted to adopt additional requirements and emission limitations applicable to oil and gas facilities in Colorado. The adopted regulatory requirements include, for example, more frequent fugitive emissions monitoring, a statewide GHG intensity program, emission limitations for well liquids unloading, and comprehensive testing of emission control devices. The adopted regulatory requirements are expected to become final and effective in early 2022.

State-level rules applicable to our operations include regulations imposed by the Colorado Department of Public Health and Environment’s (“CDPHE”) Air Quality Control Commission, including stringent requirements relating to monitoring, recordkeeping and reporting matters. In 2020, the COGCC relied in part on a previously-performed human health risk assessment in adopting new siting requirements. The COGCC also generally prohibited the venting or flaring of natural gas during drilling, completion, and production operations.

While the State of Texas has not formally conducted a recent rulemaking related to air emissions, scrutiny of oil and gas operations and the rules affecting them have increased in recent years. For example, EPA and environmental non-governmental organizations have conducted flyovers with optical gas imaging cameras to survey emissions from oil and gas production facilities and transmission infrastructure. In addition, the Texas Railroad Commission has increased oversight related to flaring, with reporting reviews and site inspections. While none of these activities increases our compliance obligations, they signal the potential for increased enforcement and possible rulemaking in the future.

Water Quality

The federal Clean Water Act ("CWA") and analogous state laws impose strict controls concerning the discharge into regulated waterbodies and wetlands of pollutants and fill material, including spills and leaks of crude oil and other substances. The CWA also requires approval and/or permits prior to construction, where construction will disturb certain wetlands or other federally regulated waters of the U.S. ("WOTUS"). For years, both via administrative rulemakings and actions and judicial interpretation and intervention, the definition of "WOTUS" and how it has been applied has been in flux. In 2019 and 2020, the EPA and the Army Corps of Engineers ("USACE") issued a final rule to repeal previous regulations and promulgated a new replacement rule (the "Navigable Waters Protection Rule"). The Navigable Waters Protection Rule was vacated by two separate federal district courts in late 2021. On November 18, 2021, EPA and USACE issued a pre-publication version of another rule largely reinstating the previous 1986 WOTUS rule and guidance "with certain amendments" to reflect "consideration of the agencies' statutory authority under the CWA and relevant Supreme Court decisions" (the "2021 Proposed Rule"). The 2021 Proposed Rule was published in the Federal Register on December 7, 2021. In addition to the 2021 Proposed Rule, EPA and USACE plan to develop yet another amendment to the WOTUS regulations, which will build upon the regulatory foundation in the 2021 Proposed Rule with the benefit of additional stakeholder engagement and public input. It is unknown at this time when the 2021 Proposed Rule will take effect; when the next forthcoming proposed amendments are expected; and/or whether either new rule will be challenged and withstand any challenges in federal court. Finally, in January 2022, the United States Supreme Court granted review of *Sackett vs. EPA*, which involves issues related to CWA scope and jurisdiction and could impact the current rulemaking process. Although the outcome of the 2021 Proposed Rule and additional forthcoming amendments to the WOTUS regulations is unknown, the regulations under the Biden Administration are undoubtedly more stringent in terms of the scope of WOTUS, which could ultimately change the scope of the CWA's jurisdiction and result in increased costs and delays with respect to obtaining permits for discharges of pollutants or dredge and fill activities in waters of the U.S., including regulated wetland areas. As noted above, however, things are constantly in flux and the fate of the definition of "WOTUS" under the CWA and how that ultimately will be applied by the Agencies is yet to be seen.

In May 2020, a federal court in Montana enjoined the use of nationwide permit ("NWP") 12 to construct new oil and gas-related pipelines, on the basis that the USACE had not properly consulted with the U.S. Fish and Wildlife Service when that permit was renewed in 2017 (the court later amended its ruling to allow use of NWP 12 for non-oil and gas transmission projects). The U.S. Supreme Court in July 2020 significantly narrowed the Montana court's injunction to cover only the challenged XL Pipeline. On August 11, 2021, the Ninth Circuit granted partial vacatur of the USACE's appeal of the Montana district court's opinion, holding the claim before it (the interlocutory appeals and underlying claim relative to the pipeline, which has been halted) was moot, but left to the district court the question of whether the case was moot in its entirety.

In the meantime, in September 2020 and again in January 2021, the USACE issued proposals to revise and reissue all 52 current NWPs, including No. 12, to, among other things, lessen the burden on the energy industry and address the flaws alleged in the Montana lawsuit. Although there are small differences in the September 2020 and January 2021 proposals, they do not impact the changes described below, particularly with NWP 12. The new NWPs became effective in March 2021. Among other things, under the new NWPs, existing NWP 12 was broken up into three new separate NWPs, with the new NWP 12 being limited solely to construction and maintenance of oil and gas pipelines, with other utility-related structures covered by the two new NWPs (i.e., NWP 57 for electric utility line and telecommunications activities and NWP 58 for utility line activities for water and other substances). The new 2021 version of NWP 12 has again been challenged in the District of Montana, by the same plaintiffs on the same grounds, which case is still pending. If the 2021 version of NWP 12 ultimately is invalidated or stayed by the courts, it could increase the costs and delays for oil and gas operators to construct or maintain pipelines that cross jurisdictional WOTUS.

The CWA also regulates storm water run-off from crude oil and natural gas facilities and requires storm water discharge permits for certain activities. Spill Prevention, Control and Countermeasure ("SPCC") requirements of the CWA require appropriate secondary containment, load out controls, piping controls, berms and other measures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon spill, rupture or leak.

Endangered Species

The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act and bald and golden eagles under the Bald and Golden Eagle Protection Act. Some of our operations may be located in areas that are or may be designated as habitats for endangered or threatened species or that may attract migratory birds, bald eagles or golden eagles.

Other

In October 2015, PHMSA proposed to expand its regulations in a number of ways, including increased regulation of gathering lines, even in rural areas, and proposed additional standards to revise safety regulations applicable to onshore gas transmission and gathering pipelines in 2016. In November 2021, PHMSA issued its final rule extending reporting requirements to all onshore gas gathering operators and applying a set of minimum safety requirements to certain onshore gas gathering pipelines with large diameters and high operating pressures.

Crude oil production is subject to many of the same operating hazards and environmental concerns as natural gas production, but is also subject to the risk of crude oil spills. In addition to SPCC requirements, the Oil Pollution Act of 1990 ("OPA") establishes requirements for preparation and EPA approval of Facility Response Plans and subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from crude oil spills. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Historically, we have not experienced any significant crude oil discharge or crude oil spill problems.

In February 2018, the COGCC comprehensively amended its regulations for oil, gas and water flowlines to expand requirements addressing flowline registration and safety, integrity management, leak detection and other matters. In November 2019, the COGCC further amended its flowline regulations pursuant to SB 19-181 to impose additional requirements regarding flowline mapping, operational status, certification and abandonment, among other things.

In June 2020, the COGCC amended its regulations regarding wellbore integrity. The amended rules impose additional requirements regarding the permitting, construction, operation, and closure of wells. In June 2021, the COGCC submitted a notice of rulemaking regarding its financial assurance rules. This rulemaking is expected to be completed in early 2022 and could increase the bonding requirements for our current and future oil and gas wells in Colorado.

We are also subject to rules regarding worker safety and similar matters promulgated by the U.S. Occupational Safety and Health Administration ("OSHA") and other governmental authorities. OSHA has established workplace safety standards that provide guidelines for maintaining a safe workplace in light of potential hazards, such as employee exposure to hazardous substances. To this end, OSHA adopted a new rule governing employee exposure to silica, including during hydraulic fracturing activities, in March 2016.

Human Capital Management

We believe that our employees play a critical role in the achievement of our short-term and long-term business goals. Consequently, we are committed to attracting, retaining and developing highly motivated and qualified employees who share our core values.

Employee Engagement and Retention

We recognize and support the growth of our employees by offering internal and external development programs. We utilize an online training platform to allocate and track employee trainings and offer on-demand developmental training content. In 2021, our employees completed approximately 7,200 hours in aggregate within our platform alone on a variety of training topics to strengthen their skills and advance their careers. These trainings were provided through a virtual environment as a response to COVID-19.

As of December 31, 2021, we had 535 full-time employees, 254 of whom are employed in field operations. During 2021, our voluntary turnover was around 10 percent. Our employees are not covered by collective bargaining agreements. We consider relations with our employees to be generally positive.

Health and Safety Culture

We are committed to the health, safety, and welfare of our employees, contractors, and neighbors. We regularly update our safety policies and procedures in an effort to ensure we are meeting or, where possible, exceeding new requirements and adopting new technologies to responsibly improve our operations. Additionally, all PDC field employees receive safety training upon hire and attend frequent meetings and refreshers to reinforce safety as a core value and our most important strategic priority. As a result of our commitment to health and safety, we have exceeded over three years without a lost time incident in either basin.

Our continual commitment to safety has resulted in improved safety records. Since the time Occupational Safety and Health Administration ("OSHA") began requiring record-keeping and publication of health and safety information in 1972, we have not had any employee work-related fatalities. A commonly used measure of an organization's safety performance is TRIR, which represents the number of injuries requiring medical treatment per 100 full-time employees during a one-year period. We monitor this performance measure and communicate it broadly across the company. We also include both TRIR and PVAR as part of our quantitative performance metrics under our STI program. For 2021, our TRIR was well below the most recent Bureau of Labor Statistics average for our industry.

In response to the COVID-19 pandemic, we have developed, implemented and adjusted a number of safety measures to help our employees safely navigate their work and personal responsibilities.

Diversity and Inclusion

We believe diversity and inclusion provides a business with growth and increased innovation and ultimately leads to a successful workforce. We are committed to providing equal opportunity in all aspects of employment and to hiring, evaluating and promoting employees based on skills and performance. We have an employee-led diversity and inclusion project team that identifies areas for growth and improvement, building on our current efforts in respect of diversity and inclusion.

Approximately 27% of our employees are women and 21% are members of a minority group, as defined by the U.S. Equal Employment Opportunity Commission, as of December 31, 2021. As of the same date, 32% of our executives are women and 17% members of a minority group. Since the beginning of 2021, we have expanded the diversity of our board of directors by adding three new diverse members with a unique set of backgrounds.

Employee Compensation and Benefits

Our compensation program is designed to provide competitive salaries and comprehensive incentives to attract, retain and reward employees to achieve results related to our core values and strategic priorities. The structure of our compensation program provides incentives for both short-term and long-term performance. We seek fairness in total compensation and benefits with reference to external benchmarking against our peers in the industry. All full-time employees are eligible for health insurance, paid and unpaid leave, retirement benefits (including an employer match up to 10% of wages), life and disability/accident coverage, and other benefits. We also offer stock awards and profit sharing for eligible employees. We believe that our compensation and benefits package is a strong retention tool and promotes physical, mental, financial and social health within our workforce.

WHERE YOU CAN FIND ADDITIONAL INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC, which are maintained and available at *www.sec.gov*. Our SEC filings are also available free of charge from our website at *www.pdce.com* as soon as reasonably practicable after such material is filed with, or furnished to, the SEC. We also make available free of charge any of our SEC filings by mail. For a mailed copy of a report, please contact PDC Energy, Inc., Investor Relations, 1775 Sherman Street, Suite 3000, Denver, CO 80203, or call (303) 860-5800.

We recommend that you view our website for additional information, as we routinely post information that we believe is important for investors. Our website can be used to access such information as our recent news releases, committee charters, code of business conduct and ethics, stockholder communication policy, director nomination procedures, sustainability report and our whistle blower hotline. While we recommend that you view our website, the information available on our website is not part of this report and is not incorporated by reference.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as the value of an investment in our common stock or other securities.

Risks Relating to the Global COVID-19 Pandemic

Our operations have been adversely affected as a result of the ongoing global COVID-19 pandemic. In particular, the pandemic contributed to a dramatic decrease in overall global economic activity generally, and crude oil prices in particular, in early 2020, and decreases in commodity prices can have a variety of negative effects on our business. While many of the adverse effects of the COVID-19 pandemic on our business have receded, it continues to be a unpredictable, particularly in the light of Delta, Omicron and other variants of concern, and additional adverse impacts on our business - including depressed crude oil, natural gas, and NGL prices, reductions in force, and reduced capital expenditures - could remain a risk for an indefinite period of time.

Risks Relating to Our Business and the Industry

Crude oil, natural gas and NGL prices fluctuate and declines in these prices, or an extended period of low prices, can significantly affect the value of our assets and our financial results and may impede our growth.

Many aspects of our business depend upon crude oil, natural gas and NGL prices, including:

- our revenue, profitability and cash flows;
- our liquidity;
- the quantity and present value of our reserves;
- the borrowing base under our revolving credit facility and access to other sources of capital; and
- the nature and scale of our operations.

The markets for crude oil, natural gas and NGLs are often volatile, and prices may fluctuate in response to, among other things:

- changes in regional, national or global economic conditions and trends, including supply and demand;
- geopolitical factors and events that reduce or increase production from oil-producing regions and/or from members of the Organization of Petroleum Exporting Countries ("OPEC"), and global events, such as the ongoing COVID-19 pandemic; and
- regulatory changes.

The price of oil has historically been volatile, due in recent years to a combination of factors including increased U.S. supply and global economic concerns. In the past two years, oil prices have ranged from highs over $80 per barrel to lows of approximately negative $40 per barrel. Prices for natural gas and NGLs have also experienced substantial volatility. If we reduce our capital expenditures due to low prices, natural declines in production from our wells will result in reduced cash flow from operations. Reduced cash flow would limit our ability to make the capital expenditures necessary to replace our reserves and production.

In addition to factors generally affecting the price of crude oil, natural gas and NGLs, the prices we receive for our production are affected by factors specific to us and to the local markets where production occurs. The prices we receive for our production vary from the relevant benchmark prices that are used for calculating commodity derivative positions. These differences, or differentials, are difficult to predict and may widen or narrow in the future based on markets and other forces, including local or regional supply and demand factors; terms of our sales contracts; investment decisions made by providers of midstream facilities and services, refineries and other industry participants; and the overall regulatory and economic climate. Widening differentials may materially and adversely impact our business.

We may be unable to return capital to our stockholders, and there is no assurance we will pay any dividends on or repurchase shares of our common stock in the future or at levels anticipated by our stockholders.

During each of the second, third and fourth quarters of 2021, our board of directors declared and paid a quarterly cash dividend of $0.12 per share of common stock, and in December 2021, our board declared and paid a special cash dividend of

$0.50 per share of common stock. Our ability to pay cash dividends in the future depends on, among other things, our liquidity, financial condition, financial requirements, contractual restrictions, restrictions imposed by applicable law and other factors considered relevant by our board. Our board, based on this evaluation, may decide not to declare future dividends, or to declare dividends at rates less than anticipated, either of which could reduce overall returns to our stockholders.

In February 2022, our board of directors has also approved an increase to our Stock Repurchase Program to acquire up to $1.25 billion of our outstanding common stock through December 31, 2023. This program is being implemented at the discretion of our board and may be extended, modified or discontinued at any time. We suspended the program in March 2020 due to adverse market conditions but reinstated it in February 2021.

Our overall capital return program may change from time to time, and we cannot guarantee we will continue to pay dividends or repurchase shares. Our announcement of capital return programs does not obligate us to pay any particular dividend amount (except with respect to dividends already declared) or repurchase any specific dollar amount or number of shares of common stock. A reduction, suspension or change in our capital return programs could have a negative effect on our stock price.

We are subject to complex federal, state, local and other laws and regulations that adversely affect the cost and manner of doing business. Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us.

Our exploration, development, production and marketing operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning crude oil and natural gas wells and associated facilities. Under these laws and regulations, we could also be liable for personal injuries, property damage and natural resource or other damages, and could be required to change, suspend or terminate operations. A summary of certain laws and regulations that apply to us and some potential changes to those laws and regulations is set forth in *Items 1 and 2 - Business and Properties - Governmental Regulation*. Any of the currently applicable laws and regulations could be amended, including in ways that we do not anticipate, and those changes could adversely affect our operations.

From time to time, we have been subject to sanctions and lawsuits relating to alleged noncompliance with regulatory requirements. For example, in October 2017, in order to settle a lawsuit brought against us by the U.S. Department of Justice, on behalf of the EPA and the State of Colorado, we entered into a consent decree pursuant to which we paid a fine and agreed to implement certain operational changes. The lawsuit claimed that we failed to operate and maintain certain equipment in compliance with applicable law. In addition, as a result of the SRC Acquisition, we are subject to the obligations and requirements of a 2018 Compliance Order on Consent (“COC”) entered into by SRC with CDPHE, applicable to certain SRC oil and gas production facilities we acquired from SRC. The COC resolved SRC’s alleged violations related to storage tank emissions and contains requirements similar to those contained in our consent decree.

The regulatory environment in which we operate also changes frequently, often through the imposition of new or more stringent environmental and other requirements, some of which may apply retroactively. We cannot predict the nature, timing, cost or effect of such additional requirements, but they may have a variety of adverse effects on us. The types of regulatory changes that could impact our operations vary widely and include, but are not limited to, the following:

- As discussed in *Items 1 and 2, Business and Properties - Governmental Regulation*, the COGCC completed extensive rulemaking hearings in November 2020 which resulted in the adoption of new requirements for setbacks, permitting, siting cumulative and surface impacts, asset transfers, venting and flaring, and remediation. The implementation of the final rules could have a significant adverse effect on our unpermitted locations and therefore on our future inventory and reserves. For example, the new planning and permitting process associated with long term, landscape level development (referred to as Comprehensive Area Plans) has not yet been successfully utilized by any operators in Colorado due to a lengthy, highly technical, and resource-intensive approval process. The COGCC is still in the process of issuing guidance and direction regarding the new requirements, and we cannot predict the impact of these requirements on our inventory and operations.
- Federal and various state, local and regional governmental authorities have implemented, or considered implementing, regulations that seek to limit or discourage the emission of carbon, methane and other GHGs. For example, the EPA has made findings and issued regulations that require us to establish and report an inventory of

greenhouse gas emissions, and the state of Colorado has adopted rules regulating methane emissions from oil and gas operations. Additional laws or regulations intended to restrict the emission of GHGs could require us to incur additional operating costs and could adversely affect demand for the oil, natural gas and NGLs that we sell. These new laws or rules could, among other things, require us to install new emission controls on our equipment and facilities, acquire allowances to authorize our GHG emissions, pay taxes related to our emissions and administer and manage a GHG emissions program. In addition, like other energy companies, we could be named as a defendant in GHG-related lawsuits.

- Proposals are made from time to time to amend U.S. federal and state tax laws in ways that would be adverse to us, including by eliminating certain key U.S. federal income tax preferences currently available with respect to crude oil and natural gas exploration and production. The changes could include (i) the repeal of the percentage depletion deduction for crude oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Also, state severance taxes may increase in the states in which we operate. This could adversely affect our existing operations in the relevant state and the economic viability of future drilling.
- The development of new environmental initiatives or regulations related to the acquisition, withdrawal, storage and use of surface water or groundwater or treatment and discharge of water waste, may limit our ability to use techniques such as hydraulic fracturing, increase our development and operating costs and cause delays, interruptions or termination of our operations, any of which could have an adverse effect on our operations and financial condition.

Increasing scrutiny and changing expectations from stakeholders with respect to our ESG practices may impose additional costs on us or expose us to new or additional risks.

Publicly traded companies, both in the oil and natural gas industry and otherwise, are facing increased scrutiny from stakeholders of our practices related to ESG. Attention on these issues may come from stakeholders ranging from the SEC to local governments to institutional investors, and these stakeholders may seek certain outcomes or results on issues they perceive to be material. This could result in reduced access to capital, shareholder proposals and other adverse effects. Companies that fail to adapt or comply with evolving stakeholder expectations, or are perceived as failing to respond appropriately, could suffer from reputational damage and the business, financial condition, and/or stock price of such a company could be materially and adversely impacted.

We have experienced increased pressure from our stakeholders focused on climate change to reduce our carbon footprint and prioritize sustainable energy practices. Our stakeholders may also require us to implement additional ESG procedures or standards in order to meet their expectations for continued investment.

We have publicly communicated commitments related to reductions in methane and greenhouse gas emissions and flaring. It is possible that our stakeholders may not be satisfied with these commitments or our progress towards them. This, or a failure to meet our targets, could lead to decreased access to capital or have a negative impact on our stock price.

Additionally, public sentiment related to the oil and gas industry may be affected by uncertainty or instability resulting from climate change, political leadership changes and subsequent policies, changes in social views regarding the importance of fossil fuels, concerns about environmental impact and investor expectations, resulting in decreased demand for our products. This could have a significant financial and operational impact on our business.

A substantial part of our crude oil, natural gas and NGLs production is located in the Wattenberg Field, making us vulnerable to risks associated with operating primarily in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing formations.

Although we have significant leasehold positions in the Delaware Basin in Texas, our current production is primarily located in the Wattenberg Field in Colorado. Because our production is not as diversified geographically as many of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including natural disasters, government regulations and midstream interruptions.

For example, bottlenecks in processing and transportation that have occurred in some recent periods in the Wattenberg Field have negatively affected our results of operations, and these adverse effects may be disproportionately severe to us compared to our more geographically diverse competitors. Similarly, the concentration of our producing assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules that could adversely affect development activities or production relating to those formations. Such an event could have a material adverse effect on our results of operations and financial condition. In addition, the demand for, and cost of, drilling rigs, equipment, supplies, chemicals, personnel and oilfield services often increase as a result of numerous factors including increases in exploration and production activity, supply chain problems, and labor shortages. Any shortages or increased costs could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital forecast, which could have a material adverse effect on our business, financial condition or results of operations. All of the producing properties and reserves we acquired in the SRC Acquisition are located in the Wattenberg Field. As a result, the transaction increased the risks we face with respect to the geographic concentration of our properties.

The marketability of our production is dependent upon transportation and processing facilities which we do not control. If these facilities are unavailable, or if we are unable to access these facilities on commercially reasonable terms, our operations could be interrupted, negatively affecting our results of operations.

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

Availability or capacity issues can be a result of depressed commodity prices that ultimately reduce investment in new midstream facilities, new or amended government regulations curtailing drilling activities in Colorado which could discourage investment in midstream facilities, protests over construction of new pipelines and facilities, weather, fire, or other reasons, and could negatively affect our results of operations. In addition to causing production curtailments, capacity constraints can also reduce the price we receive for the crude oil, natural gas and NGLs we produce.

Like other producers, we from time to time enter into volume commitments with midstream providers in order to induce them to provide increased capacity. If our production falls below the level required under these agreements, we could be subject to substantial shortfalls, deficiency, or similar fees.

Our undeveloped acreage must be drilled before lease expiration, and production must thereafter be maintained under applicable lease terms, to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells and thereafter maintain production under applicable lease terms could result in substantial lease renewal costs or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established and thereafter maintained under applicable lease terms within the spacing or pooled units covering our undeveloped acreage, our leases for such acreage will expire. The cost to renew such leases may increase significantly and we may not be able to renew such leases on commercially reasonable terms or at all. Unexpected lease expirations could occur if our actual drilling activities or our ongoing production differ materially from our current expectations, and this could result in impairment charges. The risk of lease expiration is greater at times and in areas where the pace of our exploration and development activity slows or production declines or is otherwise shut-in. Our ability to drill, develop, and maintain production under applicable lease terms from the locations necessary to maintain our leases depends on a number of factors, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, and regulatory approvals, all of which are subject to risks and uncertainties.

We may incur losses as a result of title defects in the properties in which we invest or acquire.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform record title examinations before we acquire oil and gas leases and related interests. The existence of a material title deficiency can decrease a lease's value and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

Our ability to produce crude oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of or recycle the water we use at a reasonable cost, in a timely manner and within applicable environmental rules.

Drilling and development activities such as hydraulic fracturing require the use of water and result in the production of wastewater. Our operations could be adversely impacted if we are unable to locate sufficient amounts of water or dispose of or recycle water used and produced in our exploration and production operations. The quantity of water required in certain completion operations, such as hydraulic fracturing, and changing regulations governing usage may lead to water constraints, supply concerns and regulatory issues, particularly in relatively arid climates such as eastern Colorado and western Texas. For example, increased drilling activity in the Delaware Basin in recent years has led to heightened concerns about water supply issues in the area and this may lead to regulatory actions, including rules providing local governments greater authority over water use, that adversely impact our operations.

Our operations depend on being able to reuse or dispose of wastewater in a timely and economic fashion. Wastewater from oil and gas operations is often disposed of through underground injection. Wells in the Delaware Basin typically produce relatively large amounts of water that require disposal and an increased number of earthquakes have been detected in the Delaware Basin in recent years. Some studies have linked earthquakes, or induced seismicity, in certain areas to underground injection, which is leading to increased public and regulatory scrutiny of injection safety. This increased scrutiny applied to our Colorado operations as well. For example, in November 2020, the COGCC adopted various new requirements on the underground injection of fluid waste. In December 2021, the Texas Railroad Commission suspended the deep injection of wastewater in the Gardendale Seismic Response Area.

Reduced commodity prices could result in significant impairment charges and significant downward revisions of proved reserves.

Commodity prices are volatile. Significant and rapid declines in prices have occurred in the past and may occur in the future. Low commodity prices could result in, among other things, significant impairment charges in the future. For example, we incurred impairment charges in a number of recent periods, including charges of $882.4 million and $38.5 million in 2020 and 2019, respectively, to write down assets. Similarly, the significant decline in commodity pricing during 2020 resulted in a reduced year-end proved reserve NYMEX price of $39.57 per barrel of crude and $1.99 per MMBtu of natural gas, a decrease of 29% and 23% respectively from 2019. The decline in pricing resulted in a downward revision of 28.2 MMBoe to reserves for year-end 2020 when compared to year-end 2019. The cash flow model we use to assess properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production and commodity prices, the outlook for forward commodity prices and operating and development costs. All inputs to the cash flow model must be evaluated at each date the estimate of future cash flows is made for each producing basin. A significant decrease in long-term forward prices could result in a significant impairment for our properties.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating crude oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. In determining the estimates of reserve and economic evaluations, management utilizes independent petroleum engineers. The reserve estimates are based on assumptions regarding commodity prices, production levels and operating and development costs that may prove to be incorrect. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be inaccurate and revisions in existing reserve estimates occur.

Reserve estimates are based on the volumes of crude oil, natural gas and NGLs that are anticipated to be economically recoverable from a given date forward based on economic conditions that exist at that date. The actual quantities of crude oil, natural gas and NGLs recovered will be different than the reserve estimates, in part because they will not be produced under the same economic conditions as are used for the reserve calculations.

You should not assume that the present value of the estimated future net cash flows from our proved reserves is the current market value of those reserves. Pursuant to SEC rules, the estimated discounted future net cash flows from our proved reserves, and the estimated quantity of those reserves, are based on the average of the previous 12-months' first day of the month prices and costs as of the date of the estimate. Actual future prices and costs may be materially different. Further, actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production and changes in governmental regulations or taxes. Significant variances could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K and cause potential impairment charges. In addition, the 10 percent discount factor we use when calculating discounted future net cash flows (the rate required by the SEC) may not be the most appropriate discount factor based on interest rates currently in effect and risks associated with our properties or the industry in general.

Unless reserves are replaced as they are produced, our reserves and production will decline, which would adversely affect our future business, financial condition and results of operations. We may not be able to develop our identified drilling locations as planned.

Producing crude oil, natural gas and NGL reservoirs are generally characterized by declining production rates that may vary over time and exceed our estimates depending upon reservoir characteristics and other factors. Our future reserves and production and, therefore, our cash flows and income, are highly dependent on our ability to efficiently develop and exploit our current reserves and to economically find or acquire additional recoverable reserves. We may not be able to develop, discover or acquire additional reserves to replace our current and future production at acceptable costs. Our failure to do so would adversely affect our future operations, financial condition and results of operations.

We have identified a number of well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including:

- crude oil, natural gas and NGL prices;
- the availability and cost of capital;
- drilling and production costs;
- availability and cost of drilling rigs, and equipment, supplies, chemicals, personnel and oilfield services;
- drilling results;
- lease expirations or limitations as to depth;
- midstream constraints;
- access to and availability of water sourcing and distribution systems;
- regulatory approvals; and
- other factors.

Because of these factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce crude oil, natural gas or NGLs from these or any other potential well locations. In addition, the number of drilling locations available to us will depend in part on the spacing of wells in our operating areas. An increase in well density in an area could result in additional locations in that area, but a reduced production performance from the area on a per-well basis. Conversely, a decrease in well density could result in fewer locations in an area but possibly increased production performance on a per-well basis. For example, after examining well performance and other factors, we recently determined that our current Delaware Basin position supports fewer wells per unit than previously assumed. Accordingly, as of December 31, 2021, our estimated well locations for our current Delaware Basin position decreased from 135 to 65.

Further, certain of the horizontal wells we intend to drill in the future may require pooling of our lease interests with the interests of third parties. Some states, including Colorado, allow the involuntary pooling of tracts in a relatively broad number of circumstances to facilitate exploration, though Colorado now requires applicants to own or secure consent from the owners of more than 45 percent of the minerals to be pooled. Other states, notably Texas, restrict involuntary pooling to a much narrower set of circumstances and consequently these states rely primarily on voluntary pooling of lands and leases. In states such as Texas where pooling is accomplished primarily on a voluntary basis, or in states such as Colorado if we cannot meet the minimum requirement for ownership and consent, it may be more difficult to form units and, therefore, more difficult to fully develop a project if we own less than all (or cannot secure the ownership or consent of the required minimum amount) of the leasehold in the proposed units or one or more of our leases in the proposed units does not provide the necessary pooling authority. If third parties in the proposed units are unwilling to pool their interests with ours, we may be unable to require such pooling on a timely basis or at all, which would limit the total horizontal wells we can drill. Further, the number of available locations will depend in part on the expected lateral lengths of the horizontal wells we drill. Because the intended lateral length of a horizontal well is subject to change for a variety of reasons, our estimated drilling locations will change over time. For this and numerous other reasons, our actual drilling activities may materially differ from those presently identified.

Our inventory of drilling projects includes locations in addition to those that we currently classify as proved, probable and possible. The development of and results from these additional projects are more uncertain than those relating to probable and possible locations, and significantly more uncertain than those relating to proved locations. We have generally continued a steady pace of development in the Wattenberg Field over the past several years, and while the SRC Acquisition increased our inventory, continued development has reduced our inventory drilling locations. We also anticipate that our remaining locations in the field will not, on average, be as productive or as economic as many of those we have drilled in recent years, due to lower anticipated overall production or higher gas-to-oil ratios. In the Delaware Basin, our inventory is subject to, among other things, potential lease expirations (as to acreage and/or depths) and our continued analysis of geologic challenges in certain areas. For example, as noted above, we recently reduced our estimated number of locations in the Delaware Basin due to geological issues.

The wells we drill may not yield crude oil, natural gas or NGLs in commercially viable quantities and productive wells may be less successful than we expect.

A prospect is a property on which our geologists have identified what they believe, based on available information, to be indications of hydrocarbon-bearing rocks. However, given the limitations of available data and technology, our geologists cannot know conclusively prior to drilling and testing whether crude oil, natural gas or NGLs will be present in sufficient quantities to repay drilling or completion costs and generate a profit. Furthermore, even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques do not enable our geologists to be certain as to the quantity of the hydrocarbons in those structures. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. If a well is determined to be dry or uneconomic, which can occur even though it contains some crude oil, natural gas or NGLs, it is classified as a dry hole and plugged and abandoned in accordance with applicable regulations. This generally results in the loss of the entire cost of drilling and completion to that point. Even wells that are completed and placed into production may not produce sufficient crude oil, natural gas and NGLs to be profitable, or they may be less productive and/or profitable than we expected. For example, the data we use to model anticipated results from wells in a particular area may prove to be not representative of actual results from typical wells in the area, and this could result in production that falls short of estimates reflected in our internal business plans and/or guidance, “type curve” or other disclosures we make to the public. This risk is higher for us in certain areas in the Delaware Basin that have relatively complex geological characteristics and correspondingly greater variability in well results. In addition, initial results from a well are not necessarily indicative of its performance over a longer period.

Drilling for and producing crude oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

Drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling can be unprofitable, not only due to dry holes, but also due to curtailments, delays or cancellations as a result of other factors, including:

- pressures or irregularities in geological formations;
- fires;
- floods, winter storms and other natural disasters and adverse weather conditions;
- loss of well control;
- loss of drilling fluid circulation and other facility or equipment malfunctions;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delays in the delivery of equipment and services;
- unanticipated environmental liabilities; and
- compliance with environmental and other governmental requirements.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, loss of wells, pollution, environmental contamination and regulatory penalties. For example, a loss of containment of hydrocarbons during drilling activities could potentially subject us to civil and/or criminal liability and the possibility of substantial costs, including for environmental remediation. We maintain insurance against various losses and liabilities arising from our operations; however, insurance against certain operational risks may not be available or may be prohibitively expensive relative to the perceived risks presented. In addition, we may not have coverage with respect to a pollution event if we are unaware of the event while it is occurring and are therefore unable to report the occurrence of the event to our insurance company within the time frame required under our insurance policy. Thus, losses could occur for which we have no effective insurance coverage. The occurrence of an event that is not fully covered by insurance and/or governmental or third-party responses to an event could have a material adverse effect on our business activities, financial condition and results of operations. We are currently involved in various remedial and investigatory activities at some of our wells and related sites.

In addition, certain technical risks relating to the drilling of horizontal wells - including those relating to our ability to fracture stimulate the planned number of stages and to successfully run casing the length of the well bore - have increased in recent years because we have increased the average lateral length of the horizontal wells we drill. Longer-lateral wells are also typically more expensive and require more time for preparation. In addition, we use multi-well pads instead of single-well sites. The use of multi-well pad drilling increases some operational risks because problems affecting the pad or a single well could adversely affect production from all of the wells on the pad. Pad drilling can also make our overall production, and therefore our revenue and cash flows, more volatile, because production from multiple wells on a pad will typically commence simultaneously. While we believe that we will be better served by using multi-well pads with longer lateral wells, the risk component involved in such drilling will be increased in some respects, with the result that we might find it more difficult to achieve economic success in our drilling program.

The inability of one or more of our customers or other counterparties to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from our crude oil, natural gas and NGLs sales or joint interest billings to a small number of third parties in the energy industry. This concentration of customers and joint interest owners may affect our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our commodity derivatives expose us to credit risk in the event of nonperformance by counterparties. Nonperformance by our customers or derivative counterparties may adversely affect our financial condition and profitability. We face similar risks with respect to our other counterparties, including the lenders under our revolving credit facility and the providers of our insurance coverage.

We participate in oil and gas operations with third parties who may not be able to fulfill their commitments to our projects.

We frequently own less than all of the working interest in the oil and gas leases and/or wells on which we conduct operations. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities, arising from the actions of the other owners. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, may declare bankruptcy. In the event any of our project partners does not pay its share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover the costs from the partner. This could materially adversely affect our financial position.

We may not be able to keep pace with technological developments in our industry.

Our industry is characterized by rapid and significant technological advancements. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those or other new technologies at substantial cost. In addition, our competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we were unable to use the most advanced technology, our business, financial condition and results of operations could be materially adversely affected.

Competition in our industry is intense, which may adversely affect our ability to succeed.

Our industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce crude oil, natural gas and NGLs, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive properties and exploratory prospects or evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, larger companies may have a greater ability to continue exploration activities during periods of low commodity prices. Larger competitors may also be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which could adversely affect our competitive position. These factors could adversely affect our operations and our profitability.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel.

Our future success depends to a large extent on the services of our key employees. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

A failure to complete successful acquisitions would limit our ability to replace our reserves and impact our financial condition.

Because our crude oil and natural gas properties are depleting assets, our future reserves, production volumes and cash flows depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. In addition, we continue to strive to achieve greater efficiencies in our drilling program, and our ability to do so is dependent in part on our ability to complete asset exchanges and other acquisitions that allow us to increase our working interests in particular properties. We may not be able to identify attractive acquisition opportunities, and if we do identify an appropriate acquisition candidate, we may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. If we are unable to complete suitable acquisitions on acceptable terms, it will be more difficult to replace our reserves, and an inability to replace our reserves would have a material adverse effect on our financial condition and results of operations.

Acquisitions of properties are subject to the uncertainties of evaluating recoverable reserves and potential liabilities, including environmental uncertainties.

Acquisitions of producing and undeveloped properties have been an important part of our growth over time. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, development potential, future commodity prices, operating costs, title issues and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we generally perform engineering, environmental, geological and geophysical reviews of the acquired properties that we believe are generally consistent with customary industry practices. However, such reviews are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not typically inspect every well prior to an acquisition and our ability to evaluate undeveloped acreage is inherently imprecise. Even when we inspect a well, we may not always discover structural, subsurface and environmental problems that may exist or arise after the acquisition. In some cases, our review prior to signing a definitive purchase agreement may be even more limited. In addition, we often acquire acreage without any warranty of title except as to claims made by, through or under the transferor.

When we acquire properties, we will generally have potential exposure to liabilities and costs for environmental and other problems existing on the acquired properties, and these liabilities may exceed our estimates. We may not be entitled to contractual indemnification associated with acquired properties. We often acquire interests in properties on an “as is” basis with no or limited remedies for breaches of representations and warranties. Therefore, we could incur significant unknown liabilities, including environmental liabilities or losses due to title defects, in connection with acquisitions for which we have limited or no contractual remedies or insurance coverage. In addition, the acquisition of undeveloped acreage is subject to many inherent risks and we may not be able to realize efficiently, or at all, the assumed or expected economic benefits of acreage that we acquire.

Additionally, significant acquisitions can change the nature of our operations depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or may be in different geographic locations than our existing properties. These factors can increase the risks associated with an acquisition. Acquisitions also present risks associated with the additional indebtedness that may be required to finance the purchase price and any related increase in interest expense or other related charges.

Some of our acquisitions are structured as asset trades or exchanges. These transactions may give rise to any or all of the foregoing risks. In addition, transactions of this type create a risk that we will undervalue the properties we transfer to the counterparty in the trade or exchange or overvalue the properties we receive. Such an undervaluation or overvaluation would result in the transaction being less favorable to us than we expected.

We operate in a litigious environment. The cost of defending any suits brought against us, and any judgments or settlements resulting from such suits, could have an adverse effect on our results of operations and financial condition.

Like many oil and gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, employment litigation, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of our business. For example, in January 2021, a purported class action lawsuit was filed against us by a royalty owner alleging we have been improperly deducting certain post-production costs from the owner’s oil royalty payments. While we intend to vigorously defend this suit, the outcome of legal proceedings is inherently uncertain. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management attention and other factors. In addition, the resolution of any such legal or other proceedings could result in penalties or sanctions, settlement costs and/or judgments, consent decrees or orders requiring a change in our business practices, any of which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties, sanctions or costs may be insufficient. Judgments and estimates to determine accruals or the anticipated range of potential losses related to legal and other proceedings could change from one period to the next, and such changes could be material. Information regarding legal proceedings can be found in *Item 3. Legal Proceedings* included elsewhere in this report.

Our business could be negatively impacted by security threats, including cybersecurity threats and other disruptions.

We face various security threats, including attempts by third parties to gain unauthorized access to, or control of, competitive information or to render data or systems corrupted or unusable; threats to the safety of our employees; threats to the security of our infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. There can be no assurance that the procedures and controls we use to monitor these threats and mitigate our exposure to them will be sufficient to prevent them from materializing.

Our industry has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain exploration, development and production activities. We depend on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to store, transmit, process and record sensitive information (including but not limited to trade secrets, employee information and financial and operating data), communicate with our employees and business partners, and for many other activities related to our business. In addition, computer systems control the oil and gas production and processing equipment that are necessary to deliver our production to market. Critical infrastructure targets, such as energy-related assets and transportation assets, may be at greater risk of future cyber-attacks than other targets. A disruption or failure of these systems, or of the networks and infrastructure on which they rely, may cause damage to critical production, distribution and/or storage assets, delay or prevent delivery to markets, or make it difficult to accurately account for production and settle transactions. The various procedures, facilities, infrastructure and controls we utilize to monitor these threats and mitigate our exposure to such threats are costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. The continuing and evolving threat of cybersecurity attacks has resulted in increased regulatory focus on prevention, which could potentially elevate costs, and failure to comply with these regulations could result in penalties and potential legal liability.

As dependence on digital technologies has increased in our industry, cyber incidents, including deliberate attacks and unintentional events, have also increased. Our systems and infrastructure are, and those of our business partners, including vendors, service providers, operating partners, purchasers of our production and financial institutions may be, subject to damage or interruption from a number of potential sources including natural disasters, software viruses or other malware, power failures, cyber-attacks and other events. We and our business partners also face various other cyber-security threats from criminal hackers, state-sponsored intrusion, industrial espionage and employee malfeasance, including threats to gain access to sensitive information or to render data or systems unusable.

Our technologies, systems and networks, and those of our business partners, may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, theft of property or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. To our knowledge, we have not suffered material losses related to cyber-attacks to date; however, there can be no assurance that we will not suffer material losses in the future either as a result of an interruption to or a breach of our systems or those of our third-party vendors and service providers. If we were successfully attacked, we could incur substantial remediation and other costs or suffer other negative consequences, such as a loss of competitive information, critical infrastructure, personnel or capabilities essential to our operations. Events of this nature could have a material adverse effect on our reputation, financial condition, results of operations or cash flows. Moreover, as the sophistication of cyber-attacks continues to evolve, we may be required to expend significant additional resources to further enhance our digital security or to remediate vulnerabilities.

The physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects. An economy-wide transition to lower GHG energy sources could have a variety of adverse effects on our operations and financial results.

Many scientists have shown that increasing concentrations of carbon dioxide, methane and other GHGs in the Earth's atmosphere are changing global climate patterns. One consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such events were to occur, or become more frequent, our operations could be adversely affected in various ways, including through damage to our facilities or from increased costs for insurance.

Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. As a result, if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

Efforts by governments, international bodies, businesses and consumers to reduce GHGs and otherwise mitigate the effects of climate change are ongoing. The nature of these efforts and their effects on our business are inherently unpredictable and subject to change. Certain regulatory responses to climate change issues are discussed above under the heading *"We are subject to complex federal, state, local and other laws and regulations that adversely affect the cost and manner of doing business. Changes in laws and regulations applicable to us could increase our costs, impose additional operating restrictions or have other adverse effects on us"* and in Items 1 and 2 - Business and Properties - Governmental Regulation. However, actions taken by private parties in anticipation of, or to facilitate, a transition to a lower-GHG economy will affect us as well. For example, our cost of capital may increase if lenders or other market participants decline to invest in fossil fuel-related companies for regulatory or reputational reasons. Similarly, increased demand for low-carbon or renewable energy sources from consumers could reduce the demand for, and the price of, the products we produce. Technological changes, such as developments in renewable energy and low-carbon transportation, could also adversely affect demand for our products.

Risks Relating to Financial Matters

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our production and reserves, and ultimately our profitability. Lender hesitancy to offer financing to our industry may increase this risk.

Our industry is capital intensive. We expect to continue to make substantial capital expenditures for the exploration, development, production and acquisition of crude oil, natural gas and NGL reserves. To date, we have financed capital expenditures primarily with bank borrowings under our revolving credit facility, cash generated from operations and proceeds from capital markets transactions and the sale of properties. We intend to finance our future capital expenditures utilizing similar financing sources. Our cash flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the amount of crude oil, natural gas and NGLs we are able to produce from existing wells;
- the prices at which crude oil, natural gas and NGLs are sold;
- the costs to produce crude oil, natural gas and NGLs; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower commodity prices, operating difficulties or for any other reason, our need for capital from other sources could increase, and there can be no assurance that such other sources of capital would be available at that time on reasonable terms or at all. If we raise funds by issuing additional equity securities, this would have a dilutive effect on existing shareholders. If we raise funds through the incurrence of debt, the risks we face with respect to our indebtedness would increase and we would incur additional interest expense.

Additionally, due to recent default rates in the oil and gas industry and other factors, some lenders have expressed a hesitancy to lend to oil and gas producers, and may require terms less favorable to the producers or, in some cases, may refuse to provide financing to the industry altogether. The number of lenders participating in our revolving credit facility decreased in connection with the amendment and restatement of the facility in 2021, and may decline further in the future. Our inability to obtain sufficient financing on acceptable terms would adversely affect our financial condition and profitability.

The cost of servicing, and risks related to refinancing, our debt could adversely affect our business. Those risks could increase if we incur more debt.

As of December 31, 2021, we had a total long-term debt of $950 million. Servicing our indebtedness and satisfying our other obligations will require a significant amount of cash, and cash flow from operating activities and other sources may not be sufficient to fund our liquidity needs. Our ability to pay interest and principal on our indebtedness and to satisfy our other obligations will depend on our future operating performance, our financial condition and the availability of refinancing indebtedness, which will be affected by prevailing economic conditions and financial, business and other factors, many of which are beyond our control.

A substantial decrease in our operating cash flow or an increase in our expenses could make it difficult for us to meet debt service requirements and could require us to modify our operations, including by curtailing our exploration and drilling programs, reducing our capital expenditures, selling assets, refinancing all or a portion of our existing debt or obtaining additional financing. We may or may not be able to complete any such steps on satisfactory terms. Any ability to generate sufficient cash flows to satisfy our debt obligations or contractual commitments, or to refinance our debt on commercially reasonable terms, could materially and adversely affect our financial condition and results of operations.

Covenants in our debt agreements currently impose, and future financing agreements may impose, operating and financial restrictions.

Our current debt agreements contain restrictions, and future financing agreements may contain additional restrictions, on our activities, including covenants that restrict our and our restricted subsidiaries' ability to:

- incur additional debt;
- pay dividends on, redeem or repurchase stock;
- create certain liens;
- make specified types of investments;
- apply net proceeds from certain asset sales;
- engage in transactions with our affiliates;
- engage in sales and leaseback transactions;
- merge or consolidate; and
- sell, assign, transfer, lease, convey or dispose of assets.

Our revolving credit facility is secured by substantially all of our oil and gas properties as well as a pledge of all ownership interests in our current operating subsidiaries. The restrictions contained in our current or future debt agreements may prevent us from taking actions that we believe would be in the best interest of our business. In addition, our ability to comply with covenants and restrictions in our debt agreements in the future is uncertain and will be affected by the levels of cash flows from operations and events or circumstances beyond our control. Our failure to comply with any of these restrictions and covenants could result in a default under our debt agreements. In the event of such a default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder, and under other agreements to which a cross-default or cross-acceleration provision applies, to be due and payable, together with accrued and unpaid interest; the lenders under our revolving credit facility could elect to terminate their commitments, cease making further loans and institute foreclosure proceedings against our assets; and we could be forced into bankruptcy or liquidation.

Our lenders have sole discretion to set our borrowing availability based on anticipated commodity prices and corporate outlook.

The revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based upon projected revenues from the properties securing their loan. Decreases in the price of crude oil, natural gas or NGLs may have an adverse effect on the borrowing base. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Outstanding borrowings in excess of the borrowing base must be repaid immediately unless we pledge other crude oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility. Our inability to borrow additional funds under our revolving credit facility could adversely affect our operations and our financial results.

Our commodity derivative activities could result in financial losses or reduced income from failure to perform by our counterparties, could limit our potential gains from increases in prices and could result in volatility in our net income.

We use commodity derivatives for a portion of the production from our own wells to achieve more predictable cash flows, to reduce exposure to adverse fluctuations in commodity prices, and to allow our natural gas marketing company to offer pricing options to natural gas sellers and purchasers. These arrangements expose us to the risk of financial loss in some circumstances, including when purchases or sales are different than expected or the counterparty to the commodity derivative contract defaults on its contractual obligations. In addition, many of our commodity derivative contracts are based on WTI or another crude oil or natural gas index price. The risk that the differential between the index price and the price we receive for the relevant production may change unexpectedly makes it more difficult to hedge effectively and increases the risk of a hedging-related loss. Also, commodity derivative arrangements may limit the benefit we would otherwise receive from increases in the prices for the relevant commodity.

At December 31, 2021, we had hedged a total of 22.2 MMBbls crude oil for 2022 to 2024 and 102.5 MMBtu of natural gas for 2022 and 2023. These hedges may be inadequate to protect us from continuing and prolonged declines in crude oil and natural gas prices.

Since we do not designate our commodity derivatives as cash flow hedges, we do not currently qualify for use of hedge accounting; therefore, changes in the fair value of commodity derivatives are recorded in our income statements and our net income is subject to greater volatility than it would be if our commodity derivative instruments qualified for hedge accounting. For instance, if commodity prices rise significantly, this could result in significant non-cash charges during the relevant period, which could have a material negative effect on our net income.

The price of our common stock has been and may continue to be highly volatile, which may make it difficult for shareholders to sell our common stock when desired or at attractive prices.

The market price of our common stock is highly volatile and we expect it to continue to be volatile for the foreseeable future. Adverse events including changes in production volumes, worldwide demand and prices for crude oil and natural gas, regulatory developments, and changes in securities analysts’ estimates of our financial performance could negatively impact the market price of our common stock. General market conditions, including the level of, and fluctuations in, the trading prices of stocks generally could also have a similar negative impact. The stock markets regularly experience price and volume volatility that affects many companies’ stock prices without regard to the operating performance of those companies. Volatility of this type may affect the trading price of our common stock. Similar factors could also affect the trading prices of our senior notes.

Risks Relating to Pending Great Western Acquisition

If completed, the Great Western Acquisition may not achieve its intended results and may result in us assuming unanticipated liabilities. To date, we have conducted only limited diligence regarding the assets and liabilities we would assume in the transaction.

We entered into the Purchase Agreement with the expectation that the Great Western Acquisition would result in various benefits, growth opportunities and synergies. Achieving the anticipated benefits of the transaction is subject to a number of risks and uncertainties. For example, under the Purchase Agreement, we have the opportunity to conduct customary environmental and title due diligence following the execution of the agreement, but our diligence efforts to date have been limited. As a result, we may discover title defects or adverse environmental or other conditions of which we are currently unaware. Environmental, title and other problems could reduce the value of the properties to us, and, depending on the circumstances, we could have limited or no recourse to the sellers with respect to those problems. We would assume substantially all of the liabilities associated with the acquired properties and would be entitled to indemnification in connection with those liabilities in only limited circumstances and in limited amounts. We cannot assure you that such potential remedies will be adequate for any liabilities we incur, and such liabilities could be significant.

As with other acquisitions, the success of the Great Western Acquisition depends on, among other things, the accuracy of our assessment of the reserves and drilling locations associated with the acquired properties, future oil, NGL and natural gas prices and operating costs and various other factors. These assessments are necessarily inexact. As a result, we may not recover the purchase price for the acquisition from the sale of production from the property or recognize an acceptable return from such sales.

The reserves, production and drilling locations estimates with respect to the properties to be acquired in the Great Western Acquisition may differ materially from the actual amounts.

Our estimates of the reserves, production and drilling locations associated with the properties to be acquired in the Great Western Acquisition are based on our analysis of historical production data, assumptions regarding capital expenditures and anticipated production declines. Such analysis is based, in significant part, on data provided by the sellers. We cannot assure you that these estimates are accurate. After such data is further reviewed by us and our independent engineers, the actual reserves, production and number of viable drilling locations may differ materially from the amounts we have estimated.

The transactions contemplated by the Purchase Agreement are subject to conditions that may not be satisfied on a timely basis or at all. Failure to complete the transactions contemplated by the Purchase Agreement could have material and adverse effects on us.

Completion of the Great Western Acquisition is subject to a number of conditions, including the accuracy of the parties' representations in the Purchase Agreement and the receipt of certain governmental approvals. Such conditions, some of which are beyond our control, may not be satisfied or waived in a timely manner or at all and therefore make the completion and timing of the completion of the Great Western Acquisition uncertain. In addition, the Purchase Agreement contains certain termination rights for both Great Western and us, which if exercised will also result in the Great Western Acquisition not being consummated. Furthermore, the governmental authorities from which the federal regulatory approvals are required may impose conditions on the completion of the Great Western Acquisition or require changes to the terms of the acquisition or the Purchase Agreement.

If the transactions contemplated by the Purchase Agreement are not completed, our business may be adversely affected and, without realizing any of the benefits of having completed the Great Western Acquisition, we will be subject to a number of risks, including the following: we will be required to pay our costs relating to the Great Western Acquisition, such as legal, accounting, and financial advisory fees; time and resources committed by our management to matters relating to the Great Western Acquisition could otherwise have been devoted to pursuing other beneficial opportunities; and the market price of our common stock could be impacted to the extent that the current market price reflects a market assumption that the Great Western Acquisition will be completed. In addition, if the Purchase Agreement is terminated and the Board seeks another acquisition, we cannot be certain that we will be able to find a party willing to enter into a transaction as attractive to us as the Great Western Acquisition.

We will be subject to business uncertainties while the Great Western Acquisition is pending, which could adversely affect our business.

It is possible that certain persons with whom we have a business relationship may delay certain business decisions relating to us, or seek to terminate, change or renegotiate their relationships with us, in connection with the pendency of the Great Western Acquisition. This could negatively affect our revenues, earnings and cash flows, as well as the market price of our common stock, regardless of whether the Great Western Acquisition is completed. Also, our ability to attract, retain and motivate employees may be impaired until the Great Western Acquisition is completed and for a period of time thereafter as current and prospective employees may experience uncertainty about their roles within the combined company following the transaction.

In addition, under the terms of the Purchase Agreement, we are subject to certain restrictions on the conduct of our business prior to the completion of the Great Western Acquisition, which may adversely affect our ability to execute certain of our business strategies. Such limitations could negatively affect our business and operations prior to the completion of the Great Western Acquisition.

Even if the Great Western Acquisition is completed, we may not achieve the anticipated benefits and the Great Western Acquisition may disrupt our current plans or operations.

The success of the Great Western Acquisition will depend, in part, on our ability to realize the anticipated benefits and cost savings from combining our and Great Western's businesses, and there can be no assurance that we will be able to successfully integrate Great Western or otherwise realize the anticipated benefits of the Great Western Acquisition. Difficulties in integrating Great Western into our company may result in us performing differently than expected, in operational challenges or in the failure to realize anticipated expense-related efficiencies. Potential difficulties that may be encountered in the integration process include, among others:

- the inability to successfully integrate Great Western into PDC in a manner that permits us to achieve the full cost savings or operating synergies anticipated from the Great Western Acquisition;
- complexities associated with managing a larger, more complex, integrated business;
- the disruption or the loss of momentum in, each company's ongoing business or inconsistencies in standards, controls, procedures and policies.

We are expected to incur significant transaction costs in connection with the Great Western Acquisition, which may be in excess of those we currently anticipate.

We expect to incur a number of non-recurring costs associated with negotiating and completing the Great Western Acquisition, combining the operations of the two companies and achieving desired synergies. These fees and costs have been, and will continue to be, substantial and, in many cases, will be borne by us whether or not the Great Western Acquisition is completed. A substantial majority of our non-recurring expenses will consist of transaction costs related to the Great Western Acquisition and include, among others, fees paid to financial, legal, accounting and other advisors. We will also incur transaction costs related to formulating and implementing integration plans, including facilities and systems consolidation costs and other employment-related costs. We will continue to assess the magnitude of these costs, and we may incur additional unanticipated costs. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may not offset integration-related costs and achieve a net benefit in the near term or at all. The costs described above and any unanticipated costs and expenses, many of which will be borne by us even if the Great Western Acquisition is not completed, could have an adverse effect on our financial condition and operating results.

After the Great Western Acquisition is completed, PDC will be proportionally more exposed to regulatory risks associated with oil and gas operations in Colorado and other risks associated with a more geographically-concentrated asset base.

PDC's principal assets in terms of production and reserves are located in the Wattenberg Field located within the Denver-Julesburg Basin of Colorado, but we also have a significant acreage position in the Delaware Basin in Texas. During 2021, 87 percent of PDC's production came from its assets in Colorado and 13 percent came from its assets in Texas. All of Great Western's properties, and all of its current production and reserves, are located in Colorado. Various new regulatory requirements applicable to oil and natural gas operations in Colorado have been proposed or adopted in recent years as described elsewhere in this report.

The increased percentage of PDC's combined production located in the Wattenberg Field following the Great Western Acquisition will proportionately increase PDC's exposure to risks associated with operating in a more concentrated geographic area, including Colorado-specific regulatory and midstream risks as described elsewhere in this section.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in *Note 13 - Commitments and Contingencies - Litigation and Legal Items* included in *Item 8. Financial Statements and Supplementary Data* to our consolidated financial statements included elsewhere in this report.

Environmental. Due to the nature of the natural gas and oil 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 December 31, 2021 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 in the 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. In August 2020, the COGCC issued a Notice of Alleged Violation ("NOAV") citing a failure to comply with reclamation requirements at multiple locations. To resolve the alleged violations 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.

On August 30, 2021 and November 1, 2021, the COGCC issued us NOAVs related to the timing of wellhead pressure test reporting for certain wells in the Wattenberg Field. Pursuant to the NOAVs, we have conducted and submitted a comprehensive audit of our wellhead pressure testing and reporting processes. We are actively updating our processes 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.

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.

Clean Air Act Agreement and Related Consent Decree. We continue to implement the requirements of a consent decree entered into with the CDPHE in 2017, as well as a revised compliance order on consent, the latter of which was modified by the CDPHE after the SRC Acquisition was completed. Per the terms of the agreements, we will apply for termination in early 2022. Over the course of this execution, we have identified certain immaterial deficiencies in our implementation of the programs. 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, including any sanctions associated with these deficiencies, 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 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock, par value $0.01 per share, is traded on the NASDAQ Global Select Market under the symbol "PDCE". As of February 15, 2022, we had approximately 386 stockholders of record.

In May 2021, our board of directors approved the Company's quarterly dividend program and we announced the initiation of a quarterly dividend in the amount of $0.12 per share of our common stock. We declared and paid an aggregate amount of $0.86 per share of our common stock during 2021, which included a special dividend of $0.50 per share of our common stock declared and paid in the fourth quarter of 2021. The dividend program and payment of any future dividends thereunder will be made at the discretion of our board of directors and will depend on our results of operations, cash flows, financial position and capital requirements, as well as general business conditions, legal, tax and regulatory restrictions and other factors our board of directors deems relevant at the time it determines to declare such dividends.

Additionally, our revolving credit facility, as well as the indentures governing our 2024 Senior Notes and our 5.75% senior notes due 2026 (the "2026 Senior Notes"), the terms of which are summarized in *Note 10 - Long-term Debt* in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report, include restrictions based on our leverage and other certain financial metrics that could impact our ability to pay cash dividends. As we declare dividends in the future, we will monitor compliance with such restrictions.

The following table presents information about our purchases of our common stock during the year ended December 31, 2021:

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 *(in millions)*
January	28,831	$ 23.27	—	$ 346.8
February	53,401	32.25	2,289	346.7
March	596,388	36.99	595,460	324.7
April	345,614	35.36	255,268	315.7
May	211,555	40.14	210,310	307.3
June	201,576	46.39	196,070	298.2
July	283,191	41.10	280,000	286.7
August	915,811	39.30	915,000	250.7
September	281,058	43.47	281,058	238.5
October	54,680	45.54	50,000	236.2
November	275,200	54.48	275,200	221.2
December	692,800	48.95	692,800	187.3
Total purchases	3,940,105	$ 42.16	3,753,455	$ 187.3

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(1) In April 2019, our board of directors approved a program to acquire up to $200.0 million of our outstanding common stock and in August 2019, effective with the closing of the SRC Acquisition, increased such amount to $525.0 million (the "Stock Repurchase Program"). 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. We reinstated our Stock Repurchase Program in late February 2021 and in February 2022, our board of directors increased the size of the program to $1.25 billion and extended it through December 31, 2023.

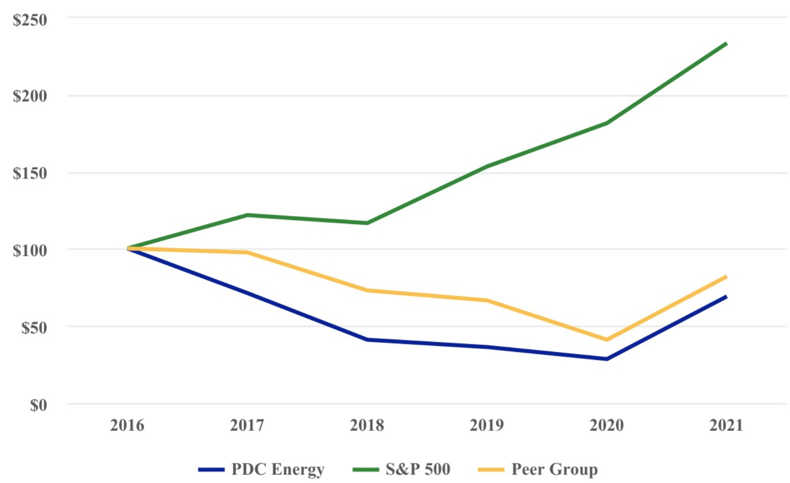
(2) Purchases outside of the Stock Repurchase Program represent shares withheld from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans. The withheld shares are not considered common stock repurchased under the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

Stockholder Performance Graph

The following performance graph and related information shall deemed to be furnished, but not filed with the SEC.

The graph below matches the cumulative 5-Year total return of our common stock with the cumulative total returns of the Standard and Poor's ("S&P") 500 Index and a customized peer group of 126 companies. The cumulative total stockholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our common stock on December 31, 2016 and tracks it through December 31, 2021, in the S&P 500 Index and in the customized peer group on the same date. The results shown in the graph below are not necessarily indicative of future stock price performance.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN
Among PDC Energy, Inc., the S&P 500 Index,
and a Peer Group



	Year Ended December 31,					
	2016	2017	2018	2019	2020	2021
PDC Energy	100.00	71.01	41.00	36.06	28.29	69.20
S&P 500	100.00	121.83	116.49	153.17	181.35	233.41
Peer Group	100.00	97.71	72.90	66.54	40.68	81.79

ITEM 6. [RESERVED]

This Item has been omitted as we are no longer required to provide five years of selected financial data.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included in *Item 8. Financial Statements and Supplementary Data* and also with *Item 1A. Risk Factors* of this report. A discussion of changes in our results of operations and liquidity from 2019 to 2020 has been omitted from this report but can be found in *Item 7. Management's Discussion and Analysis*, of our Annual Report on Form 10-K for the year ended December 31, 2020, filed with the SEC on February 25, 2021. Further, we encourage you to review the *Special Note Regarding Forward-Looking Statements* in Part I of this report.

EXECUTIVE SUMMARY

2021 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

In 2020, the COVID-19 pandemic led to a significant decline in commodity prices due to the decrease in demand for crude oil, negatively impacting crude oil and natural gas producers, such as PDC. Due to the decrease in oil demand, the Organization of Petroleum Exporting Countries ("OPEC") and other oil producing countries significantly decreased production, resulting in a low level of global supply. During 2021, the global economy slowly recovered from the impacts of COVID-19 and related variants through vaccination distributions. The recovery of the global economy was supported by gradual increases to production volumes from OPEC and other oil producing countries; however, demand growth exceeded the production increases, resulting in higher commodity prices compared to pre-COVID-19 prices. The commodity price environment may remain volatile for an extended period due to, among other things, outbreaks caused by coronavirus variants, the recovery of the economy, unexpected supply disruptions in key producing countries, geopolitical disputes, weather conditions, and ongoing investor and regulatory pressure to replace fossil fuel consumption with lower carbon emission alternatives.

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 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 than recent levels.

Financial Matters

Twelve months ended December 31, 2021

- Production volumes increased 4 percent to 71.3 MMboe in 2021 compared to 2020 as a result of our full-year drilling and completion program during 2021.

- Crude oil, natural gas and NGLs sales increased to $2.6 billion in 2021 compared to $1.2 billion in 2020, primarily due to the 112 percent increase in weighted average realized commodity prices.

- Incurred negative net settlements from our commodity derivative contracts of $410.2 million compared to positive net settlements of $279.3 million in 2020 due to improvement in commodity prices during 2021.

- Combined revenue from crude oil, natural gas and NGLs sales and net settlements from our commodity derivative instruments increased 50 percent to $2.1 billion from $1.4 billion in 2020.

- Generated net income of $522.3 million, or $5.22 per diluted share, compared to a net loss of $724.3 million, or $7.37 per diluted share, in 2020. The net income during the period compared to the net loss in the prior period was significantly impacted by an increase in crude oil, natural gas and NGLs sales of $1,400.0 million and an $882.4 million impairment charge recognized in 2020. These positive factors were partially offset by an increased loss of $881.7 million in commodity price risk management and $105.8 million in additional production taxes between periods.

- Adjusted EBITDAX, a non-U.S. GAAP financial measure, was $1,593.8 million compared to $990.6 million in 2020, primarily due to an increase in sales of $710.5 million, net of negative net derivative settlements.

- Cash flows from operations increased to $1,547.8 million compared to $870.1 million in 2020. Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased to $1,532.6 million compared to $921.6 million in 2020. Adjusted free cash flows, a non-U.S. GAAP financial measure, increased to $949.0 million from $399.3 million in 2020.

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.

Pending Acquisition

On February 26, 2022, we entered into the Acquisition Agreement to acquire Great Western for approximately $1.3 billion, inclusive of Great Western's net debt. Great Western is an in dependent oil and gas company focused on the exploration, production and development of crude oil and natural gas in Colorado. We anticipate acquiring approximately 54,000 net acres in the Core Wattenberg and production of approximately 55,000 Boe per day. Under the terms of the Acquisition Agreement, the purchase price of the Great Western Acquisition will consist of approximately 4.0 million shares of our common stock and approximately $543 million in cash. The cash portion of the purchase price is expected to be funded through a combination of cash on hand and availability under our revolving credit facility. We expect the Great Western Acquisition to be completed in the second quarter of 2022, subject to certain customary closing conditions. Upon a successful close, we anticipate adding between $225 million and $275 million to our planned 2022 Wattenberg capital investment. See *Item 1A. Risk Factors* for risk factors related to the Great Western Acquisition of this report.

Drilling, Completion and Vertical Well Abandonment Overview

During 2021, we operated one full-time drilling rig, one spudder rig and one full-time completion crew in the Wattenberg Field. In addition, we operated one full-time drilling rig and one part-time completion crew, which started in March and ended in June, in the Delaware Basin. Our total capital investments in crude oil and natural gas properties for the year ended December 31, 2021 were $583.7 million. We operated a full-time workover rig in the Wattenberg Field in 2021 for use in our plugging and abandonment program. This program focused on our legacy vertical wells to assist in our horizontal drilling program and to reduce our overall produced well emissions. We spent $30.5 million on this program in 2021.

The following table summarize our drilling, completion and vertical well abandonment activities for the year ended December 31, 2021:

	Operated Wells					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2020	214	201.8	20	19.0	234	220.8
Wells spud	78	74.2	19	19.0	97	93.2
Wells turned-in-line	(149)	(143.0)	(18)	(17.4)	(167)	(160.4)
In-process as of December 31, 2021	143	133.0	21	20.6	164	153.6
Plugged and abandoned - Vertical Wells	404	392.0	—	—	404	392.0

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.

Debt Reductions and Capital Returns

Debt Reduction. During the year ended December 31, 2021, we significantly reduced our indebtedness by $670.3 million. This reduction included net repayments of $168.0 million on our revolving credit facility, resulting in no outstanding balance at the period end. On September 15, 2021, we redeemed and retired our 2021 Convertible Notes with a cash payment for the principal amount of $200 million, plus accrued and unpaid interest. Additionally, on November 3, 2021, we redeemed the aggregate $200 million principal amount of our outstanding 2024 Senior Notes at a redemption price of 101.531 percent of the principal plus accrued and unpaid interest, leaving an aggregate principal amount outstanding of $200 million. Finally, on December 1, 2021, we redeemed the remaining $102.3 million principal amount of our outstanding 6.25% Senior Notes due in 2025 (the “2025 Senior Notes”) at a redemption price of 103.125 percent of the principal plus accrued and unpaid interest.

The redemptions of our 2021 Convertible Notes and 2025 Senior Notes as well as the partial redemption of our 2024 Senior Notes were financed by our cash flows from operations.

Stock Repurchase Program. In February 2021, we reinstated our Stock Repurchase Program. During the year ended December 31, 2021, we repurchased 3.8 million shares of outstanding common stock at a cost of $159.5 million. As of December 31, 2021, $187.3 million remained available under the program. In February 2022, our board of directors increased the size of the program to $1.25 billion, which we anticipate fully utilizing by December 31, 2023.

Dividends. In the second quarter of 2021, our board of directors commenced the declaration and payment of quarterly cash dividends of $0.12 per share of our common stock. In December 2021, our board of directors declared and paid a special dividend of $0.50 per share of our common stock in addition to the regular fourth quarter dividend declared. For the year ended December 31, 2021, our dividends paid totaled $0.86 per share of common stock or $83.6 million in the aggregate.

2022 Operational and Financial Outlook

We anticipate that our production for 2022 will range between 195,000 Boe to 205,000 Boe per day, approximately 62,000 Bbls to 65,000 Bbls of which are expected to be crude oil. Our planned 2022 capital investments in crude oil and natural gas properties, which we expect to be between $675 million and $725 million, are focused on continued execution of our development plans in the Wattenberg Field and the Delaware Basin. Our 2022 capital investments budget incorporates an increase in both basins relating to service cost inflation resulting in an estimated cost increase of approximately 10 to 15 percent per well, based on costs we have experienced since the third quarter of 2021.

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. We may revise our 2022 capital investment program during the year as a result of, among other things, changes in commodity prices or our internal long-term outlook for commodity prices, requirements to hold acreage, the cost of services for drilling and well completion activities, drilling results, changes in our borrowing capacity, a significant change in cash flows, regulatory issues, requirements to maintain continuous activity on leaseholds and acquisition and divestiture opportunities.

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, and Summit development areas. Our 2022 capital investment program for the Wattenberg Field represents approximately 75 percent of our expected total capital investments in crude oil and natural gas properties. In 2022, the majority of the wells we plan to drill are 1.5 mile and 2.0 mile lateral wells in the Wattenberg Field. In 2022, we anticipate spudding approximately 130 to 145 operated wells and turning-in-line approximately 115 to 130 operated wells. As of December 31, 2021, we have approximately 145 gross operated DUCs and 235 approved permitted locations. In 2022, we expect to add a rig in March, bringing us to two full-time horizontal rigs and one completion crew along with a part-time spudder rig.

Delaware Basin. Total capital investments in crude oil and natural gas properties in the Delaware Basin for 2022 are expected to be approximately 25 percent of our total capital investments. In 2022, we anticipate spudding and turning-in-line approximately 15 to 20 operated wells. The majority of the wells we plan to drill in 2022 in the Delaware Basin are 2.0 mile lateral wells.

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 $0.25 per share. Then we expect to use approximately 60% or more of our remaining adjusted free cash flows, 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.

As part of SB 19-181, a series of rulemaking hearings were conducted, which focused on issues such as permitting requirements, setbacks and siting requirements, resulting in the adoption of new regulatory requirements. Rulemakings focused on financial assurance and permit fees have not been completed. The financial assurance rulemaking could result in increased bonding requirements, though the final language and impact will not be known until early 2022.

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. As of January 2021, permits are now designed as Oil and Gas Development Plans (“OGDP”), which 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. As both CAPs and OGDPs are new processes and the COGCC staff is working to develop the appropriate requirements and adjusting to their new operating plan, the time needed to obtain a permit has been prolonged. COGCC rules provide that the permitting process could range between six to twelve months or more from submission to approval.

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. PDC was granted unanimous approval for an 8-well OGDP located in rural Weld County in October 2021, our first approval under the new permitting process resulting from a company-wide collaborative effort. As part of the permit process, we successfully obtained consent from all nearby residents and landowners, which was an option designed by the COGCC for locations with residential building units within 2,000 feet. Additionally, in September, we submitted our application for an OGDP covering an approximate 70-well, multi-pad development plan. We anticipate a COGCC determination on approval of this OGDP in the second quarter of 2022.

In December, PDC submitted our first CAP. The application proposes approximately 450 wells spread amongst 25 surface locations in Weld County, 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. 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. We anticipate a COGCC determination on approval of our CAP by year end 2022 or early 2023, recognizing that there may be delays in this new process.

Together, these applications represent our planned Wattenberg Field turn-in-line activity into 2027.

Environmental, Social and Governance

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 newly created ESG&N Committee at the board of directors and is applied at every level of our business.

We recognize the importance of reducing our environmental footprint and have created proactive programs and targets related to emission reduction. These initiatives, which include the plugging and abandonment of legacy vertical wells, retrofits of air pneumatics on older facilities, electrification of our facilities, technological innovations and other activities, require capital and operational investments which are proactively and regularly built into our annual budgeting process. We anticipate approximately $80 million in spending relating to ESG in 2022, which include certain expenditures to ensure compliance with state regulations and the plugging and abandonment of approximately 300 legacy vertical wells. We anticipate a similar level of annual spending over the next several years relating to ESG and compliance to achieve our emission target goals outlined below. We do not anticipate these projects having a material impact on our operations. However, we may revise our 2022 ESG budget during the year as a result of, among other things, changes in commodity prices or our internal long-term outlook for commodity prices, a significant change in cash flows or regulatory developments.

During 2021, we implemented the following ESG initiatives:

- Formalized our board oversight of ESG issues by incorporating ESG into our N&G Committee, which became the ESG&N Committee.
- Issued a Sustainability Report addressing a variety of ESG and sustainability matters, including significant Sustainability Accounting Standards Board compliance. The Sustainability Report is available on our website at www.pdce.com and is not incorporated by reference in this report.
- Continued board of directors refreshment by adding two diverse directors and one additional diverse director in February 2022, reflecting a commitment to diversity, refreshment and independence.
- Set aggressive targets to (i) reduce greenhouse gas intensity by 60% from 2020 emissions by 2025 and 74% by 2030, (ii) reduce methane emissions intensity by 50% from 2020 emissions by 2025 and 70% by 2030, and (iii) eliminate routine flaring by 2025.

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

Results of Operations

Summary of Operating Results

The following table presents selected information regarding our operating results for the periods presented:

	Year Ended December 31,			Percent Change	
	2021	2020	2019	2021-2020	2020-2019
	(dollars in millions, except per unit data)				
Production:					
Crude oil (MBbls)	22,682	23,720	19,166	(4)%	24 %
Natural gas (MMcf)	175,747	165,637	115,950	6 %	43 %
NGLs (MBbls)	19,360	17,042	10,923	14 %	56 %
Crude oil equivalent (MBoe)	71,333	68,368	49,414	4 %	38 %
Average Boe per day (Boe)	195,433	186,798	135,381	5 %	38 %
Crude Oil, Natural Gas and NGLs Sales:					
Crude oil	$ 1,530.8	$ 816.8	$ 1,020.7	87 %	(20)%
Natural gas	519.6	178.8	151.0	191 %	18 %
NGLs	502.2	157.0	135.6	220 %	16 %
Total crude oil, natural gas and NGLs sales	$ 2,552.6	$ 1,152.6	$ 1,307.3	121 %	(12)%
Net Settlements on Commodity Derivatives:					
Crude oil	$ (289.1)	$ 294.4	$ (18.3)	(198)%	*
Natural gas	(121.1)	(15.1)	0.7	*	*
Total net settlements on derivatives	$ (410.2)	$ 279.3	$ (17.6)	(247)%	*
Average Sales Price (excluding net settlements on derivatives):					
Crude oil (per Bbl)	$ 67.49	$ 34.44	$ 53.26	96 %	(35)%
Natural gas (per Mcf)	2.96	1.08	1.30	174 %	(17)%
NGLs (per Bbl)	25.94	9.21	12.41	182 %	(26)%
Crude oil equivalent (per Boe)	35.78	16.86	26.46	112 %	(36)%
Average Costs and Expense (per Boe):					
Lease operating expense	$ 2.53	$ 2.36	$ 2.88	7 %	(18)%
Production taxes	2.32	0.87	1.63	167 %	(47)%
Transportation, gathering and processing expenses	1.41	1.14	0.94	24 %	21 %
General and administrative expense	1.79	2.36	3.27	(24)%	(28)%
Depreciation, depletion and amortization	8.90	9.06	13.04	(2)%	(31)%
Lease Operating Expense by Operating Region (per Boe):					
Wattenberg Field	$ 2.19	$ 2.15	$ 2.50	2 %	(14)%
Delaware Basin	4.76	3.48	4.15	37 %	(16)%

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** Percent change is not meaningful.*

Crude Oil, Natural Gas and NGLs Sales

Crude oil, natural gas and NGLs sales for the year ended December 31, 2021 increased compared to the year ended December 31, 2020 due to the following:

	Year Ended December 31, 2021
	(in millions)
Change in:	
Production	$ (3.5)
Average crude oil price	749.7
Average natural gas price	329.9
Average NGLs price	323.9
Total change in crude oil, natural gas and NGLs sales revenue	$ 1,400.0

The negative impact in sales relating to the change in production volumes during the year ended December 31, 2021 compared to 2020 was impacted by a 4 percent decrease in crude oil production between periods.

Crude Oil, Natural Gas and NGLs Production

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

	Year Ended December 31,			Percent Change	
Production by Operating Region	**2021**	**2020**	**2019**	**2021-2020**	**2020-2019**
Crude oil (MBbls)					
Wattenberg Field	18,901	19,552	14,489	(3)%	35 %
Delaware Basin	3,781	4,168	4,677	(9)%	(11)%
Total	22,682	23,720	19,166	(4)%	24 %
Natural gas (MMcf)					
Wattenberg Field	154,150	140,845	91,785	9 %	53 %
Delaware Basin	21,597	24,792	24,165	(13)%	3 %
Total	175,747	165,637	115,950	6 %	43 %
NGLs (MBbls)					
Wattenberg Field	17,300	14,495	8,198	19 %	77 %
Delaware Basin	2,060	2,547	2,725	(19)%	(7)%
Total	19,360	17,042	10,923	14 %	56 %
Crude oil equivalent (MBoe)					
Wattenberg Field	61,892	57,521	37,984	8 %	51 %
Delaware Basin	9,441	10,847	11,430	(13)%	(5)%
Total	71,333	68,368	49,414	4 %	38 %
Average crude oil equivalent per day (Boe)					
Wattenberg Field	169,567	157,161	104,066	8 %	51 %
Delaware Basin	25,866	29,637	31,315	(13)%	(5)%
Total	195,433	186,798	135,381	5 %	38 %

Net production volumes for oil, natural gas and NGLs increased 4 percent during the year ended December 31, 2021 compared to 2020. The increase in production volume between periods was primarily due to a greater number of wells turned-in-line since the fourth quarter of 2020. This increase was partially offset by normal decline in production from our existing wells and lower performance of wells turned-in-line in the Delaware Basin during 2021.

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

	Year Ended December 31,		
Production Ratio by Operating Region	**2021**	**2020**	**2019**
Wattenberg Field			
Crude oil	31 %	34 %	38 %
Natural gas	41 %	41 %	40 %
NGLs	28 %	25 %	22 %
Total	100 %	100 %	100 %
Delaware Basin			
Crude oil	40 %	38 %	41 %
Natural gas	38 %	38 %	35 %
NGLs	22 %	24 %	24 %
Total	100 %	100 %	100 %

The change in production mix in the Wattenberg Field during the year ended December 31, 2021 compared to 2020 and 2019 was driven by our 2021 development plan being focused on areas that have a higher gas/oil ratio and due to less bypass processing of gas which increased our NGLs ratio and economics.

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 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 sufficiently 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 year ended December 31, 2021. We continuously monitor infrastructure capacities versus producer activity and production volume forecasts.

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. Our weighted average realized commodity prices increased 112 percent during 2021 as compared to 2020. The NYMEX average daily crude oil and NYMEX first-of-the-month natural gas prices increased 72 percent and 81 percent, respectively, as compared to 2020.

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	**Year Ended December 31,**			**Percent Change**	
(excluding net settlements on derivatives)	**2021**	**2020**	**2019**	**2021-2020**	**2020-2019**
Crude oil (per Bbl)					
Wattenberg Field	$ 67.49	$ 34.21	$ 52.99	97 %	(35)%
Delaware Basin	67.47	35.48	54.08	90 %	(34)%
Weighted average price	67.49	34.44	53.26	96 %	(35)%
Natural gas (per Mcf)					
Wattenberg Field	2.98	1.22	1.49	144 %	(18)%
Delaware Basin	2.81	0.28	0.57	*	(51)%
Weighted average price	2.96	1.08	1.30	174 %	(17)%
NGLs (per Bbl)					
Wattenberg Field	24.77	8.84	11.51	180 %	(23)%
Delaware Basin	35.72	11.32	15.12	216 %	(25)%
Weighted average price	25.94	9.21	12.41	182 %	(26)%
Crude oil equivalent (per Boe)					
Wattenberg Field	34.95	16.84	26.31	108 %	(36)%
Delaware Basin	41.25	16.94	26.95	144 %	(37)%
Weighted average price	35.78	16.86	26.46	112 %	(36)%

** Percent change is not meaningful.*

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 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.

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)	$ 67.92	$ 67.49	99 %	$ 3.10	$ 64.39	95 %
Natural gas (per MMBtu)	3.76	2.96	79 %	0.13	2.83	75 %
NGLs (per Bbl)	67.92	25.94	38 %	—	25.94	38 %
Crude oil equivalent (per Boe)	49.29	35.78	73 %	1.30	34.48	70 %

2020	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)	$ 39.40	$ 34.44	87 %	$ 2.34	$ 32.10	81 %
Natural gas (per MMBtu)	2.08	1.08	52 %	0.12	0.96	46 %
NGLs (per Bbl)	39.40	9.21	23 %	—	9.21	23 %
Crude oil equivalent (per Boe)	28.52	16.86	59 %	1.10	15.76	55 %

2019	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)	$ 57.03	$ 53.26	93 %	$ 1.24	$ 52.02	91 %
Natural gas (per MMBtu)	2.63	1.30	49 %	0.17	1.13	43 %
NGLs (per Bbl)	57.03	12.41	22 %	0.10	12.31	22 %
Crude oil equivalent (per Boe)	40.95	26.46	65 %	0.90	25.56	62 %

(1) Average TGP expense excludes unutilized firm transportation fees of $0.11, $0.04, and $0.04 per Boe for the years ended December 31, 2021, 2020, and 2019, respectively.

Our average realization percentages for crude oil, natural gas and NGLs increased in 2021 as compared to 2020 primarily due to the overall increase in commodity prices between periods driven by the improvement in oil and gas product demand that occurred throughout 2021. Additionally, we realized improved differentials resulting from 2021 sales contracts.

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 7 - Commodity Derivative Financial Instruments* in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report for a summary of our derivative positions as of December 31, 2021.

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:

	Year Ended December 31,		
	2021	2020	2019
		(in millions)	
Commodity price risk management gain (loss), net:			
Net settlements of commodity derivative instruments:			
Crude oil collars and fixed price exchanges	$ (289.1)	$ 294.4	$ (18.3)
Natural gas collars and fixed price exchanges	(120.1)	(1.4)	8.8
Natural gas basis protection exchanges	(1.0)	(13.7)	(8.1)
Total net settlements of commodity derivative instruments	(410.2)	279.3	(17.6)
Change in fair value of unsettled commodity derivative instruments:			
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	49.3	(19.9)	(81.1)
Crude oil collars and fixed price exchanges	(269.3)	(49.8)	(62.1)
Natural gas collars and fixed price exchanges	(61.7)	(7.8)	0.1
Natural gas basis protection exchanges	(9.6)	(21.5)	(2.1)
Net change in fair value of unsettled commodity derivative instruments	(291.3)	(99.0)	(145.2)
Total commodity price risk management gain (loss), net	$ (701.5)	$ 180.3	$ (162.8)

The significant increase in commodity prices during 2021 had an overall unfavorable impact on the fair value and settlements of our commodity derivatives.

Lease Operating Expense

Lease operating ("LOE") expense increased by 12 percent to $180.7 million in 2021 compared to $161.3 million in 2020. The period-over-period increase in LOE was primarily due to (i) increased activities and payroll costs at our well locations from the COVID-19 induced downturn in 2020, (ii) $5.6 million of additional environmental and regulatory costs in 2021, and (iii) fewer vendor concessions experienced in 2021 as compared to 2020 as the price of commodities has improved. LOE per Boe increased 7 percent to $2.53 in 2021 from $2.36 in 2020.

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.

Production taxes increased 178 percent to $165.2 million in 2021 compared to $59.4 million in 2020. Production taxes per Boe increased 167 percent to $2.32 in 2021 compared to $0.87 in 2020. The increase in production taxes was primarily due to an increase in crude oil, natural gas and NGLs prices between periods.

Transportation, Gathering and Processing Expense

TGP expense increased 29 percent to $100.4 million in 2021 compared to $77.8 million in 2020. TGP per Boe increased to $1.41 for 2021 compared to $1.14 for 2020. The overall increase in TGP expense for 2021 compared to 2020 was driven by a $14.4 million increase relating to transportation of our crude oil volumes delivered and a $5.1 million increase in unutilized transportation fees relating to our delivery commitment in the Delaware Basin.

Impairment of Properties and Equipment

The following table sets forth the major components of our impairment of properties and equipment for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
		(in millions)	
Impairment of proved and unproved properties	$ 0.4	$ 881.2	$ 10.6
Impairment of infrastructure and other	—	1.2	27.9
Total impairment of properties and equipment	$ 0.4	$ 882.4	$ 38.5

There were no significant impairment charges recognized related to our proved and unproved oil and gas properties in 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.

During the first quarter of 2020, we recorded impairment charges of $881.1 million to our proved and unproved properties in the Delaware Basin. These impairment charges were due to a significant decline in crude oil prices, which was considered a triggering event that required us to assess our crude oil and natural gas properties for possible impairment.

General and Administrative Expense

General and administrative expense decreased to $127.7 million in 2021 compared to $161.1 million in 2020 primarily due to $30.0 million in transaction and transition costs incurred in 2020 related to the SRC Acquisition and consultant fees related to our ERP implementation of $5.3 million.

Depreciation, Depletion and Amortization Expense

Crude oil and natural gas properties. During 2021 and 2020, we invested $583.6 million and $522.3 million, respectively, exclusive of changes in accounts payable related to capital expenditures, in the development of our crude oil and natural gas properties. Depreciation, depletion and amortization expense ("DD&A") 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 $627.5 million and $611.0 million in 2021 and 2020, respectively. The increase in total DD&A expense was primarily due to an increase in production volumes as our weighted average depletion rate between periods was comparable. The decrease in weighted average depletion rate during 2021 compared to 2020 was driven by an increase in proved reserves in our Wattenberg Field as a result of improved commodity prices during 2021.

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

	Year Ended December 31, 2021
	(in millions)
Increase in production	$ 24.8
Decrease in weighted average depreciation, depletion and amortization rates	(8.3)
Total decrease in DD&A expense related to crude oil and natural gas properties	$ 16.5

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

	Year Ended December 31,		
	2021	2020	2019
		(per Boe)	
Operating Region/Area			
Wattenberg Field	$ 8.68	$ 8.80	$ 11.77
Delaware Basin	9.59	9.68	16.76
Total weighted average DD&A expense rate	8.80	8.94	12.92

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $7.7 million for the year ended December 31, 2021, compared to $8.7 million for the year ended December 31, 2020.

Interest Expense, net

Interest expense, net decreased by $6.0 million to $82.7 million in 2021 compared to $88.7 million in 2020. The decrease was primarily related to reduced borrowings under our revolving credit facility, a full redemption of our 2025 Senior Notes and a partial redemption of our 2024 Senior Notes. These decreases were partially offset by a $6.1 million increase in interest expense related to the issuance of an additional $150 million aggregate principal amount of the 2026 Senior Notes in September 2020 and a $6.9 million loss on extinguishment from partial redemption of our 2024 Senior Notes and full redemption of our 2025 Senior Notes.

Provision for Income Taxes

We recorded income tax expense of $26.6 million for 2021 and an income tax benefit of $7.9 million for 2020, resulting in effective tax rates of 4.8 percent and 1.1 percent on the respective pre-tax income or loss. 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 loss due to the effect of a valuation allowance against our deferred income tax assets at December 31, 2021 and 2020.

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 become deductible. At each reporting period, management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, tax planning strategies and projected future taxable income in making this assessment. The oil and gas property impairments and cumulative pre-tax losses were key considerations that led us to continue to provide a valuation allowance against our DTAs as of December 31, 2021 and 2020 since we cannot conclude that it is more likely than not that our DTAs will be fully realized in future periods.

Future events or new evidence which may lead us to conclude that it is more likely than not that our DTAs will be realized include, but are not limited to, cumulative historical pre-tax earnings, sustained or continued improvements in oil prices, and taxable events that could result from one or more transactions. Given recent improvements in oil and gas prices and improvements in our current earnings, we believe there is a reasonable possibility that, if oil and natural gas prices remain similar to December 31, 2021 pricing levels, sufficient positive evidence may become available within the next 12 months to allow us to reach a conclusion that all or a significant portion of the valuation allowance will no longer be needed. Release of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense in the period the release is recorded. However, the exact timing and amount of the valuation allowance release are subject to change based on the level of profitability that we actually achieve.

Given recent improvements in oil and gas prices and assumptions based on our current production forecasts, we estimate that we will begin to incur cash federal and state income taxes again in 2022 and 2023.

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

The factors impacting net income of $522.3 million and net loss of $724.3 million in 2021 and 2020, respectively, are discussed above.

Adjusted net income, a non-U.S. GAAP financial measure, was $799.6 million and for the year ended December 31, 2021 and adjusted net loss, a non-U.S. GAAP financial measure, was $625.3 million for the year ended December 31, 2020. With the exception of the tax-affected (when applicable) net change in fair value of unsettled derivatives, 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 December 31, 2021 is an indication of a lack of liquidity. We had working capital deficits of $461.5 million and $471.6 million at December 31, 2021 and 2020, respectively. 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 $33.8 million at December 31, 2021 and availability under our revolving credit facility was $1.48 billion, providing for total liquidity of $1.51 billion as of December 31, 2021. 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. As commodity prices improve, 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.

On February 26, 2022, we entered into the Acquisition Agreement to acquire Great Western for approximately $1.3 billion, inclusive of Great Western's net debt. Under the terms of the Acquisition Agreement, the purchase price of the Great Western Acquisition will consist of approximately 4.0 million shares of our common stock and approximately $543 million in cash. The cash portion of the purchase price is expected to be funded through a combination of cash on hand and availability under our revolving credit facility. We expect the Great Western Acquisition to be completed in the second quarter of 2022, subject to certain customary closing conditions.

Upon closing the Great Western Acquisition, we will be required to pay off and terminate Great Western's revolving credit facility, which had an outstanding balance of $242.0 million as of December 31, 2021. At closing, we are also expecting to pay off Great Western's $311.9 million 12.0% Senior Notes due September 1, 2025, plus a redemption premium. The payments of the debt balances will be funded through the 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 by approximately $1.1 billion. 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 included in *Item 8. Financial Statements and Supplementary Data* to our consolidated financial statements included elsewhere in this report.

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 to: (a) 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 December 31, 2021, we were in compliance with all covenants in the revolving credit facility with a current ratio of 3.1:1.0 and a leverage ratio of 0.6:1.0.

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:

	Year ended December 31,		
	2021	2020	2019
		(in thousands)	
Cash flows from operating activities	$ 1,547,796	$ 870,079	$ 858,226
Cash flows from investing activities	(578,804)	(687,159)	(677,772)
Cash flows from financing activities	(937,786)	(181,260)	(188,890)
Net increase (decrease) in cash and cash equivalents	$ 31,206	$ 1,660	$ (8,436)

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 expenses. Cash flows from operating activities increased by $677.7 million to $1,547.8 million in 2021 as compared to $870.1 million in 2020. The increase between periods was primarily due to a $1.4 billion increase in crude oil, natural gas and NGLs sales, a $33.4 million decrease in general and administrative expense, and changes in the timing of vendor payments. These increases were partially offset by $410.2 million in cash settlement losses on commodity derivatives in 2021 compared to $279.3 million in cash receipts from derivative settlements in 2020, a $105.8 million increase in production taxes and changes in the timing of receivable collections between periods.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $611.0 million in 2021 to $1,532.6 million from $921.6 million in 2020. 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 $549.7 million in 2021 to $949.0 million from $399.3 million in 2020. The increase was primarily due to the increase in cash flows from operating activities, as discussed above.

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 $578.8 million during 2021 was primarily related to our drilling and completion activities of $583.1 million, partially offset by $5.1 million in proceeds from the sale of certain properties and equipment.

Net cash used in investing activities of $687.2 million during 2020 was primarily related to our drilling and completion activities of $551.0 million and $139.8 million related to the closing of the SRC Acquisition.

Financing Activities. Net cash used in financing activities in 2021 of $937.8 million was primarily due to (i) net repayments on our credit facility of $168.0 million, (ii) redemption and retirement of our 2021 Convertible Notes and 2025 Senior Notes for $200 million and $105.5 million, respectively, (iii) partial redemption and retirement of our 2024 Senior Notes for $203.1 million, (iv) the repurchase of 3.8 million shares of our common stock for $156.8 million pursuant to our Stock Repurchase Program and (v) dividend payments totaling $83.6 million. Repurchases of our common stock may extend into 2023 based on current market conditions, although our 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 December 31, 2021, $187.3 million out of the approved $525 million remained available for repurchases under the program. In February 2022, our board of directors increased the size of the program to $1.25 billion, which we anticipate fully utilizing by December 31, 2023. 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.

Net cash used in financing activities in 2020 of $181.3 million was primarily due to the redemption of a portion of the 2025 Senior Notes totaling $452.2 million, the repurchase and retirement of shares of our common stock totaling $23.8 million pursuant to the Stock Repurchase Program and $9.3 million related to purchases of our stock for employee stock-based compensation tax withholding obligations. These financing cash outflows were financed by our net borrowings from our credit facility of $164 million, proceeds from the issuance of 2026 Senior Notes of $148.5 million and cash flows from operating activities.

Subsidiary Guarantor

PDC Permian, Inc., a Delaware corporation (the “Guarantor”), our wholly-owned subsidiary, guarantees our obligations under our 2024 Senior Notes and 2026 Senior Notes (collectively, the “Senior Notes”). The Guarantor holds our assets located in the Delaware Basin. The Senior Notes are fully and unconditionally guaranteed on a joint and several basis by the Guarantor. 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 consolidated financial statements. Investments in subsidiaries are accounted for under the equity method.

	As of/Year Ended December 31,			
	2021		2020	
	Issuer	Guarantor	Issuer	Guarantor
	(in millions)			
Assets				
Current assets	$ 402.6	$ 56.0	$ 271.4	$ (57.8)
Intercompany accounts receivable, guarantor subsidiary	—	40.8	107.3	—
Investment in guarantor subsidiary	1,767.2	—	1,767.2	—
Properties and equipment, net	3,875.0	939.9	3,982.1	877.1
Other non-current assets	58.5	4.8	56.6	4.3
Liabilities				
Current liabilities	$ 862.5	$ 57.6	$ 751.3	$ 28.5
Intercompany accounts payable	27.9	—	—	94.2
Long-term debt	942.1	—	1,409.5	—
Other non-current liabilities	392.3	172.0	254.9	178.1
Statement of Operations				
Crude oil, natural gas and NGLs sales	$ 2,163.1	$ 389.5	$ 968.8	$ 183.7
Commodity price risk management gain (loss), net	(701.5)	—	180.3	—
Total revenues	1,464.5	391.4	1,151.5	182.5
Production costs	892.4	189.0	740.7	177.5
Gross profit (1)	1,270.7	200.4	228.1	6.2
Impairment of properties and equipment	0.4	—	2.0	880.4
Net income (loss)	327.7	194.9	(49.2)	(670.0)

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

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with U.S. GAAP. The preparation of these statements requires us to make certain assumptions, judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities and commitments as of the date of our financial statements.

Our significant accounting policies are described in *Note 2 - Summary of Significant Accounting Policies* in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report. The following discussion outlines the accounting policies and practices involving the use of estimates and application of significant judgment that are critical in determining our financial results. Changes in the estimates and assumptions discussed below could materially affect the amount or timing of our financial results.

Crude Oil and Natural Gas Reserve Quantities

We account for our crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depleted by the unit-of-production method based on estimated proved developed producing reserves. The successful efforts method inherently relies on the estimation of proved crude oil, natural gas and NGL reserves. In determining the estimates of reserve and economic evaluations, management utilizes independent petroleum engineers. Reserve quantities and the related estimates of future net cash flows are used as inputs in our calculation of depletion, evaluation of proved properties for impairment, assessment of expected realizability of our deferred income tax assets and calculation of the standardized measure of discounted future net cash flows.

The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. Significant inputs and engineering assumptions used in developing the estimates of proved crude oil and natural gas reserves include future production volumes, future operating and development costs and historical commodity prices. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, we continually make revisions to reserve estimates as additional information becomes available. We cannot predict the amounts or timing of such future revisions.

If the estimates of proved reserve quantities decline, the rate at which we record depletion expense will increase, which would reduce future net income. Changes in depletion rate calculations caused by changes in reserve quantities are made prospectively. In addition, a decline in reserve estimates may impact the outcome of our assessment of proved and unproved properties for impairment. Impairments are recorded in the period in which they are identified.

We cannot reasonably predict future commodity prices. However, assuming all other factors are held constant, we performed a sensitivity analysis on our proved reserve estimates as of December 31, 2021, to present a decrease of approximately 10 percent in crude oil price as the value of crude oil influences the value of our proved reserves and PV-10 most significantly. Our proved reserve quantities would decrease by 4.3 MMBoe (1%) and our PV-10 of our proved reserves would decrease by $1.1 billion (11%). During 2021, we had positive revisions to our proved reserve quantities of 52.9 MMBoe as a result of higher average prices for crude oil, natural gas and NGLs. During 2020 and 2019, we had negative revisions of 39.5 and 16.5 MMBoe, respectively, as a result of lower average prices for crude oil, natural gas and NGLs. For more information regarding reserve estimations, including additional crude oil sensitives and descriptions over historical reserve revisions, see *Items 1 and 2. Business and Properties - Oil and Gas Production and Operations* and *Supplemental Oil and Gas Information* within our consolidated financial statements included in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report.

Impairment of Crude Oil and Natural Gas Properties

Upon a triggering event, we assess the valuation of our proved crude oil and natural gas properties for possible impairment by comparing the carrying value to estimated undiscounted future net cash flows on a field-by-field basis using estimated production and prices at which we estimate the commodity will be sold. If carrying values exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a discounted future cash flows analysis. We estimate the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount.

Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, and a discount factor. Future commodity prices are estimated by using a combination of assumptions management uses in its budgeting and forecasting process, historical and future prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. The discount factor used is the market based weighted average cost of capital which is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying crude oil and natural gas.

Unproved properties with individually significant acquisition costs are periodically assessed for impairment and reduced to fair value based on a review over our future development plans, estimated future cash flows for probable well locations and remaining average lease terms. Items that can impact our future development plans can be driven by drilling results, reservoir performance, capital resources and seismic interpretations. Changes in our assumptions of the estimated nonproductive portion of our undeveloped leases could result in additional impairment expense.

Although our cash flow estimates are based on the relevant information available at the time the estimates are made, estimates of future cash flows are, by their nature, highly uncertain and may vary significantly from actual results. We cannot predict when or if future impairment charges will be recorded because of the uncertainty in the factors discussed above.

There were no significant impairment charges recognized related to our proved and unproved properties during the year ended December 31, 2021. We recorded impairment charges of $881.1 million to our proved and unproved properties to our Delaware Basin properties in 2020 as a result of the significant decline in crude oil prices.

Valuation of Business Combinations

We follow the acquisition method of accounting for business combinations. Assets acquired and liabilities assumed are recognized at the date of acquisition at their respective estimated fair values. Any excess of the purchase price over the fair value amounts assigned to assets and liabilities is recorded as goodwill. Any deficiency of the purchase price over the estimated fair values of the net assets acquired is recorded as a gain in statements of operations.

In estimating the fair values of assets acquired and liabilities assumed the most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties as part of acquisition accounting, we estimate the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, and a market based weighted average cost of capital rate. Additionally, for acquisitions with significant unproved properties, we may also review comparable purchases and sales of crude oil and natural gas properties within the same regions and use that data as a basis for fair market value as such sales represent the amount at which a willing buyer and seller would enter into an exchange for such properties to determine an estimation of fair value.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in a higher depletion expense, which results in lower net earnings. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value. There were no business combinations during the year ended December 31, 2021.

Recent Accounting Pronouncements

There were no significant new accounting standards adopted or new accounting pronouncements that would have potential effect on us as of December 31, 2021.

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.

PV-10. We define PV-10 as the estimated present value of the future net cash flows from our proved reserves before income taxes, discounted using a 10 percent discount rate. We believe that PV-10 provides useful information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies. We believe that PV-10 is relevant and useful for evaluating the relative monetary significance of our reserves. Professional analysts, investors and other users of our financial statements may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies’ reserves. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable in evaluating us and our reserves. PV-10 is not intended to represent the current market value of our estimated reserves.

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:

	Year Ended December 31,		
	2021	2020	2019
		(thousands)	
Cash flows from operations to adjusted cash flows from operations and adjusted free cash flow:			
Net cash from operating activities	$ 1,547.8	$ 870.1	$ 858.2
Changes in assets and liabilities	(15.2)	51.5	(32.8)
Adjusted cash flows from operations	1,532.6	921.6	825.4
Capital expenditures for development of crude oil and natural gas properties	(583.1)	(551.0)	(855.9)
Change in accounts payable related to capital expenditures for oil and gas development activities	(0.5)	28.7	68.2
Adjusted free cash flow	$ 949.0	$ 399.3	$ 37.7
Net income (loss) to adjusted net income (loss):			
Net income (loss)	$ 522.3	$ (724.3)	$ (56.7)
Loss (gain) on commodity derivative instruments	701.5	(180.3)	162.8
Net settlements on commodity derivative instruments	(410.2)	279.3	(17.6)
Tax effect of above adjustments (1)	(14.0)	—	(35.2)
Adjusted net income (loss)	$ 799.6	$ (625.3)	$ 53.3
Net income (loss) to adjusted EBITDAX:			
Net income (loss)	$ 522.3	$ (724.3)	$ (56.7)
Loss (gain) on commodity derivative instruments	701.5	(180.3)	162.8
Net settlements on commodity derivative instruments	(410.2)	279.3	(17.6)
Non-cash stock-based compensation	23.0	22.2	23.8
Interest expense, net	82.7	88.7	71.1
Income tax expense (benefit)	26.6	(7.9)	(3.3)
Impairment of properties and equipment	0.4	882.4	38.5
Exploration, geologic and geophysical expense	1.1	1.4	4.1
Depreciation, depletion and amortization	635.2	619.7	644.2
Accretion of asset retirement obligations	12.1	10.1	6.1
Loss (gain) on sale of properties and equipment	(0.9)	(0.7)	9.7
Adjusted EBITDAX	$ 1,593.8	$ 990.6	$ 882.7
Cash from operating activities to adjusted EBITDAX:			
Net cash from operating activities	$ 1,547.8	$ 870.1	$ 858.2
Interest expense, net (2)	75.8	88.7	71.1
Amortization and write-off of debt discount, premium and issuance costs	(13.5)	(16.8)	(13.6)
Exploration, geologic and geophysical expense	1.1	1.4	4.1
Other	(2.2)	(4.3)	(4.3)
Changes in assets and liabilities	(15.2)	51.5	(32.8)
Adjusted EBITDAX	$ 1,593.8	$ 990.6	$ 882.7
PV-10:			
Standardized measure of discounted future net cash flows	$ 7,908.2	$ 3,282.2	$ 3,310.3
Present value of estimated future income tax discounted at 10%	1,800.6	172.4	526.7
PV-10	$ 9,708.8	$ 3,454.6	$ 3,837.0

(1) Due to the full valuation allowance recorded against our net deferred tax assets, there is no tax effect for the year ended December 31, 2020.
(2) Excludes loss on extinguishment from early retirement of our senior notes amounting to $6.9 million for the year ended December 31, 2021.

ITEM 7A. 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. 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 December 31, 2021, we had no outstanding borrowings under our revolving credit facility.

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 December 31, 2021, we had a net liability derivative position of $367.3 million related to our commodity price risk derivatives. Based on a sensitivity analysis as of December 31, 2021, we estimate that a 10 percent increase in
natural gas, 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 $85.1 million, whereas a 10 percent decrease in prices would have resulted in a decrease in fair value of our net derivatives liabilities of $82.5 million. The potential increase in the fair value of our net derivative liabilities would be recorded our consolidated 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. For the year ended December 31, 2021, three customers each accounted for more than 10% of our sales. For each of the years ended December 31, 2020 and 2019, four customers each accounted for more than 10%

of our sales. No other customer accounted for more than 10% of our sales during these periods. Our allowances for credit losses were insignificant as of December 31, 2021.

Disclosure of Limitations

Because the information above included only those exposures that existed at December 31, 2021, 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 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements, Financial Statement Schedule and Supplemental Information

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of PDC Energy, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of PDC Energy, Inc. and its subsidiaries (the “Company”) as of December 31, 2021 and 2020, and the related consolidated statements of operations, of stockholders’ equity and of cash flows for each of the three years in the period ended December 31, 2021, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company’s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company’s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed 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. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Oil and Natural Gas Reserves on Proved Crude Oil and Natural Gas Properties, Net

As described in Notes 2 and 8 to the consolidated financial statements, the Company’s proved crude oil and natural gas properties balance was $8,310 million as of December 31, 2021, and depreciation, depletion, and amortization (DD&A) expense for the period ended December 31, 2021 was $635.2 million. As disclosed by management, the process of estimating and evaluating crude oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. Significant inputs and engineering assumptions used in developing the estimates of proved crude oil and natural gas reserves include reserves volumes, future operating and development costs and historical commodity prices. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur. The Company accounts for crude oil and natural gas properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depleted by the unit-of-production method based on estimated proved developed producing reserves. Reserve estimates are prepared by internal and external engineers (collectively “specialists”).

The principal considerations for our determination that performing procedures relating to the impact of proved crude oil and natural gas reserves on proved crude oil and gas properties, net is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the estimates of proved crude oil and natural gas reserves, which in turn led to (ii) a high degree of auditor judgement, subjectivity, and effort in performing procedures and evaluating the audit evidence related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved crude oil and natural gas reserves related to reserves volumes and the assumptions applied to the data related to future operating and development costs, and commodity prices.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s estimates of proved crude oil and natural gas reserves. The work of specialists was used in performing the procedures to evaluate the reasonableness of the reserve volumes. As a basis for using this work, the specialists’ qualifications were understood and the Company’s relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists and an evaluation of the specialists’ results. These procedures also included, among others, testing the completeness and accuracy of data related to reserves volumes, future operating and development costs, and commodity prices. Additionally, these procedures included evaluating whether the assumptions applied to the aforementioned data were reasonable considering the past performance of the Company.

/s/PricewaterhouseCoopers LLP
Denver, Colorado
February 28, 2022

We have served as the Company’s auditor since 2007.

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

	December 31, 2021	December 31, 2020
Assets		
Current assets:		
Cash and cash equivalents	$ 33,829	$ 2,623
Accounts receivable, net	398,605	244,251
Fair value of derivatives	17,909	48,869
Prepaid expenses and other current assets	8,230	12,505
Total current assets	458,573	308,248
Properties and equipment, net	4,814,865	4,859,199
Fair value of derivatives	15,177	9,565
Other assets	48,051	60,961
Total Assets	$ 5,336,666	$ 5,237,973
Liabilities and Stockholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 127,891	$ 90,635
Production tax liability	99,583	124,475
Fair value of derivatives	304,870	98,152
Funds held for distribution	285,861	177,132
Accrued interest payable	10,482	14,734
Other accrued expenses	91,409	81,715
Current portion of long-term debt	—	193,014
Total current liabilities	920,096	779,857
Long-term debt	942,084	1,409,548
Asset retirement obligations	127,526	132,637
Fair value of derivatives	95,561	36,359
Deferred income taxes	26,383	—
Other liabilities	314,769	264,034
Total liabilities	2,426,419	2,622,435
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 96,468,071 and 99,758,720 issued as of December 31, 2021 and 2020, respectively	965	998
Additional paid-in capital	3,161,941	3,387,754
Accumulated deficit	(249,954)	(772,265)
Treasury shares - at cost, 54,960 and 37,510 as of December 31, 2021 and 2020, respectively	(2,705)	(949)
Total stockholders' equity	2,910,247	2,615,538
Total Liabilities and Stockholders' Equity	$ 5,336,666	$ 5,237,973

See accompanying Notes to Consolidated Financial Statements

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

	Year Ended December 31,		
	2021	2020	2019
Revenues			
Crude oil, natural gas and NGLs sales	$ 2,552,558	$ 1,152,555	$ 1,307,275
Commodity price risk management gain (loss), net	(701,456)	180,270	(162,844)
Other income	4,808	6,401	11,692
Total revenues	1,855,910	1,339,226	1,156,123
Costs, expenses and other			
Lease operating expense	180,659	161,346	142,248
Production taxes	165,209	59,368	80,754
Transportation, gathering and processing expense	100,403	77,835	46,353
Exploration, geologic and geophysical expense	1,064	1,376	4,054
General and administrative expense	127,733	161,087	161,753
Depreciation, depletion and amortization	635,184	619,739	644,152
Accretion of asset retirement obligations	12,086	10,072	6,117
Impairment of properties and equipment	402	882,393	38,536
Loss (gain) on sale of properties and equipment	(912)	(724)	9,734
Other expense	2,490	10,272	11,317
Total costs, expenses and other	1,224,318	1,982,764	1,145,018
Income (loss) from operations	631,592	(643,538)	11,105
Interest expense, net	(82,698)	(88,684)	(71,099)
Income (loss) before income taxes	548,894	(732,222)	(59,994)
Income tax benefit (expense)	(26,583)	7,902	3,322
Net income (loss)	$ 522,311	$ (724,320)	$ (56,672)
Earnings (loss) per share			
Basic	$ 5.30	$ (7.37)	$ (0.89)
Diluted	5.22	(7.37)	(0.89)
Weighted-average common shares outstanding			
Basic	98,546	98,251	64,032
Diluted	100,154	98,251	64,032

See accompanying Notes to Consolidated Financial Statements

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

	Year Ended December 31,		
	2021	2020	2019
Cash flows from operating activities:			
Net income (loss)	$ 522,311	$ (724,320)	$ (56,672)
Adjustments to net income (loss) to reconcile to net cash from operating activities:			
Net change in fair value of unsettled commodity derivatives	291,268	99,001	145,246
Depreciation, depletion and amortization	635,184	619,739	644,152
Impairment of properties and equipment	402	882,393	38,536
Accretion of asset retirement obligations	12,086	10,072	6,117
Non-cash stock-based compensation	23,023	22,200	23,837
(Gain) loss on sale of properties and equipment	(912)	(724)	9,734
Amortization and write-off of debt discount, premium and issuance costs	13,468	16,772	13,575
Loss from extinguishment of debt	6,927	—	—
Deferred income taxes	26,383	(6,530)	(2,256)
Other	2,451	3,004	3,155
Changes in assets and liabilities:			
Accounts receivable	(153,717)	139,664	(88,304)
Other assets	24,678	(5,341)	(11,560)
Production tax liability	41,381	(50,803)	22,240
Accounts payable and accrued expenses	40,183	(66,183)	(29,578)
Funds held for distribution	108,729	(23,621)	(7,298)
Asset retirement obligations	(28,595)	(27,491)	(21,511)
Other liabilities	(17,454)	(17,753)	168,813
Net cash from operating activities	1,547,796	870,079	858,226
Cash flows from investing activities:			
Capital expenditures for development of crude oil and natural gas properties	(583,108)	(550,964)	(855,908)
Capital expenditures for other properties and equipment	(894)	(1,634)	(20,839)
Acquisition of crude oil and natural gas properties	—	(139,812)	(13,207)
Proceeds from sale of properties and equipment	5,073	1,641	2,105
Proceeds from divestitures	125	3,610	202,076
Restricted cash	—	—	8,001
Net cash from investing activities	(578,804)	(687,159)	(677,772)
Cash flows from financing activities:			
Proceeds from revolving credit facility and other borrowings	802,800	1,799,350	1,577,000
Repayment of revolving credit facility and other borrowings	(970,800)	(1,635,350)	(1,605,500)
Proceeds from senior notes	—	148,500	—
Redemption of senior notes	(308,584)	(452,153)	—
Repayment of convertible notes	(200,000)	—	—
Payment of debt issuance costs	(13,066)	(6,538)	(72)
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	(6,038)	(9,345)	(4,003)
Purchase of treasury shares under stock repurchase program	(156,795)	(23,819)	(154,363)
Dividends paid	(83,615)	—	—
Principal payments under financing lease obligations	(1,688)	(1,905)	(1,952)
Net cash from financing activities	(937,786)	(181,260)	(188,890)
Net change in cash and cash equivalents	31,206	1,660	(8,436)
Cash and cash equivalents, beginning of year	2,623	963	9,399
Cash and cash equivalents, end of year	$ 33,829	$ 2,623	$ 963

See accompanying Notes to Consolidated Financial Statements

PDC ENERGY, INC.
Consolidated Statements of Stockholders’ Equity
(in thousands)

	Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings (Accumulated Deficit)	Total Stockholders’ Equity
	Shares	Amount		Shares	Amount		
Balance at January 1, 2019	66,149	$ 661	$ 2,519,423	(45)	$ (2,103)	$ 8,727	$ 2,526,708
Net income (loss)	—	—	—	—	—	(56,672)	(56,672)
Stock-based compensation	213	2	23,835	—	—	—	23,837
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(106)	(4,003)	—	(4,003)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(4)	—	(127)	4	127	—	—
Retirement of treasury shares	(4,706)	(46)	(154,317)	4,706	154,363	—	—
Issuance of treasury shares	—	—	(4,505)	112	4,505	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(4,706)	(154,363)	—	(154,363)
Balance at December 31, 2019	61,652	617	2,384,309	(35)	(1,474)	(47,945)	2,335,507
Net income (loss)	—	—	—	—	—	(724,320)	(724,320)
Issuance pursuant to acquisition	39,182	391	1,014,921	—	—	—	1,015,312
Stock-based compensation	530	5	19,738	—	2,457	—	22,200
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(457)	(9,345)	—	(9,345)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(339)	(3)	(7,407)	339	7,413	—	3
Retirement of treasury shares	(1,266)	(12)	(23,807)	1,266	23,819	—	—
Issuance of treasury shares	—	—	—	115	—	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(1,266)	(23,819)	—	(23,819)
Balance at December 31, 2020	99,759	998	3,387,754	(38)	(949)	(772,265)	2,615,538
Net income (loss)	—	—	—	—	—	522,311	522,311
Stock-based compensation	531	5	20,831	—	2,187	—	23,023
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(181)	(6,038)	—	(6,038)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(117)	(1)	(4,156)	117	4,157	—	—
Retirement of treasury shares	(3,705)	(37)	(157,058)	3,711	157,401	—	306
Issuance of treasury shares	—	—	—	89	—	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(3,753)	(159,463)	—	(159,463)
Dividends declared ($0.86 per share)	—	—	(85,430)	—	—	—	(85,430)
Balance at December 31, 2021	96,468	$ 965	$ 3,161,941	(55)	$ (2,705)	$ (249,954)	$ 2,910,247

See accompanying Notes to 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 December 31, 2021, we owned an interest in approximately 3,500 gross productive wells.

The accompanying audited consolidated financial statements include the accounts of PDC and our wholly-owned subsidiaries. Pursuant to the proportionate consolidation method, our accompanying consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the entities which we proportionately consolidate. All material intercompany accounts and transactions have been eliminated in consolidation.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates in the Preparation of Financial Statements. The preparation of our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") requires us to make estimates and assumptions that affect the amounts reported on our consolidated financial statements and accompanying notes. Actual results could differ from those estimates. Estimates which are particularly significant to our consolidated financial statements include estimates of proved oil and natural gas reserves used in calculating depletion; estimates of unpaid revenues and unbilled costs; future cash flows from proved oil and natural gas reserves on proved oil and natural gas properties used in impairment assessment; valuation of commodity derivative instruments; the estimation of future abandonment obligations used in asset retirement obligations; valuation of proved and unproved crude oil and natural gas properties from purchased and exchanged businesses and assets; and valuation of deferred income tax assets.

Cash and Cash Equivalents. The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. Cash and cash equivalents potentially subject us to a concentration of credit risk as substantially all of our deposits held in financial institutions were in excess of federal deposit insurance limits as of December 31, 2021 and 2020. We maintain our cash and cash equivalents in the form of money market and checking accounts with financial institutions that we believe are creditworthy and are also lenders under our revolving credit facility.

Commodity Derivative Financial Instruments. 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 to protect against price declines in future periods. We have elected not to designate any of our commodity derivative instruments as cash flow hedges; therefore, these instruments do not qualify for hedge accounting. Accordingly, changes in the fair value of our derivative instruments are recorded in the consolidated statements of operations. Under applicable accounting standards, the fair value of each derivative instrument is recorded as either an asset or liability on the consolidated balance sheet. 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, contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates, volatility factors and nonperformance risk.

Properties and Equipment.

Crude Oil and Natural Gas Properties. We account for our crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depleted by the unit-of-production method based on estimated proved developed producing reserves. We have determined that we have two unit-of-production fields: the Wattenberg Field and the Delaware Basin. In making these conclusions we consider the geographic concentration, operating similarities within the areas, geologic considerations and common cost environments in these areas. We calculate quarterly depletion expense by using our estimated prior period-end reserves as the denominator, with the exception of our fourth quarter where we use the year-end reserve estimate adjusted for fourth quarter production. The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur. Capitalized development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves. Upon the sale or retirement of significant portions of or complete fields of depreciable or depletable property, the net book value thereof, less proceeds or salvage value, is recognized as a gain or loss.

Exploration costs, including geological and geophysical expenses, seismic costs on unproved leaseholds and delay rentals are expensed as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized, but charged to expense if the well is determined to be economically nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as we have identified a sufficient quantity of reserves to justify completion as a producing well, we are making sufficient progress assessing our reserves and economic and operating viability or we have not made sufficient progress to allow for final determination of productivity. If an in-progress exploratory well is found to be economically unsuccessful prior to the issuance of the financial statements, the costs incurred prior to the end of the reporting period are charged to exploration expense. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the costs associated with the well are classified as suspended well costs until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time we are able to make a final determination of a well's productive status, the well is removed from suspended well status and the resulting accounting treatment is recorded.

Unproved property costs not subject to depletion primarily include leasehold costs, broker and legal expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Leasehold costs are transferred into costs subject to depletion on an ongoing basis as these properties are evaluated and proved reserves are established. Additional costs not subject to depletion include costs associated with development wells in progress or awaiting completion at year-end. These costs are transferred into costs subject to depletion on an ongoing basis as these wells are completed and proved reserves are established or confirmed.

Proved Property Impairment. Annually, or upon a triggering event, we assess the valuation of our proved crude oil and natural gas properties for possible impairment by comparing the carrying value to estimated undiscounted future net cash flows on a field-by-field basis using estimated production and prices at which we estimate the commodity will be sold. If carrying values exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a discounted future cash flows analysis. The impairment recorded is the amount by which the carrying values exceed the fair value. In the impairment assessment we estimate the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of future production volumes, future operating and development costs, future commodity prices, and a market based weighted average cost of capital rate. Certain events, including but not limited to downward revisions in estimates of our reserve quantities, expectations of falling commodity prices or rising capital and operating costs, could result in a triggering event, and may result to a possible impairment of our proved crude oil and natural gas properties.

Unproved Property Impairment. Acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to impairment expense. Unproved crude oil and natural gas properties with individually significant acquisition costs are assessed for impairment periodically, or if a triggering event is identified.

Other Property and Equipment. Other property and equipment such as vehicles, facilities, office furniture and equipment, buildings and computer hardware and software is carried at cost. Depreciation is provided principally on the straight-line method over the assets' estimated useful lives, which range from two to 35 years. Total depreciation expense related to other property and equipment was $7.7 million, $8.7 million and $5.7 million for the years ended December 31, 2021, 2020 and 2019, respectively.

We review other property and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying value of the asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying value of the asset exceeds the estimated future cash flows, an impairment charge is recognized for the amount by which the carrying value of the asset exceeds its fair value.

Internal-Use Software. Internal-use software costs incurred during the development stage of our enterprise resource planning software are capitalized. The development stage generally includes software design, configuration, testing and installation activities. Training and maintenance costs are expensed as incurred, while upgrades and enhancements are capitalized if it is probable that such expenditures will result in additional functionality. Capitalized internal-use software costs are depreciated over the estimated useful life of the underlying project on a straight-line basis upon completion of the project.

Capitalized Interest. We capitalize interest on expenditures made in connection with exploration and development projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring unevaluated properties to its intended use. Interest capitalized may not exceed gross interest expense for the period. Capitalized interest totaled $17.8 million, $19.7 million and $13.4 million during the year ended December 31, 2021, 2020 and 2019, respectively.

Assets Held-for-Sale. Assets held-for-sale are valued at the lower of their carrying amount or estimated fair value, less costs to sell. If the carrying amount of the assets exceeds their estimated fair value, an impairment loss is recognized. Fair values are estimated using accepted valuation techniques, such as a discounted cash flow model, earnings multiples or indicative bids, when available. We consider historical experience and all available information at the time the estimates are made; however, the fair value that is ultimately realized upon the sale of the assets to be divested may differ from the estimated fair values reflected on the consolidated financial statements. DD&A expense is not recorded on assets once they are classified as held-for-sale. Assets classified as held-for-sale are expected to be disposed of within one year.

Income Taxes. We account for income taxes under the asset and liability method. We recognize deferred income tax assets and liabilities for the future tax consequences attributable to operating loss and credit carryforwards and differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred income tax assets and liabilities are measured using enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect on deferred income tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. If we determine that it is more likely than not that some portion or all of the deferred income tax assets will not be realized, we record a valuation allowance, thereby reducing the deferred income tax assets to what we consider realizable.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. Our policy is to recognize interest and penalties related to uncertain tax positions in interest expense.

Debt Issuance Costs and Discounts. Debt issuance costs and discounts are capitalized and amortized over the life of the respective borrowings using the effective interest method. Debt issuance costs for the Senior Notes are included in long-term debt and the debt issuance costs for the revolving credit facility are included in other assets.

Asset Retirement Obligations. We recognize the estimated liability for future costs associated with the plugging and abandonment of our oil and gas properties resulting from acquisition, construction or normal operation. We account for asset retirement obligations by recording the fair value of our plugging and abandonment obligations when incurred, which is at the time the related well is completed. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the associated long-lived asset by the same amount as the liability. Over time, the liability is accreted for the change in the present value (accretion expense). The initial capitalized cost, net of salvage value, is depleted over the useful life of the related asset through a charge to DD&A expense. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost (presented as part of properties and equipment). Revisions in estimated liabilities can result from, among other things, changes in retirement costs or the estimated timing of settling asset retirement obligations.

Treasury Shares. We record treasury share purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as a reduction in shareholders' equity. When we retire treasury shares, we charge any excess of cost over the par value to additional paid-in-capital ("APIC"), to the extent we have amounts in APIC, with any remaining excess cost being charged to retained earnings.

Revenue Recognition. Crude oil, natural gas and NGLs revenues are recognized when we have transferred control of crude oil, natural gas or NGLs production to the purchaser. We consider the transfer of control to have occurred 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. We record revenues based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes based on company-measured volume readings. We then adjust our crude oil, natural gas and NGLs sales in subsequent periods based on the data received from our purchasers that reflects actual volumes delivered and prices received. We receive payment for sales one to two months after actual delivery has occurred. The differences in sales estimates and actual sales are recorded one to two months later. Historically, these differences have not been material. We account for natural gas imbalances using the sales method. For the years ending December 31, 2021, 2020 and 2019, the impact of any natural gas imbalances was not significant.

Our crude oil, natural gas and NGLs sales are recorded using either the "net-back" or "gross" method of accounting, depending upon the related 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 proceeds based on a percent of the proceeds or have fixed our sales price at index less specified deductions. The net-back method results in the recognition of a net sales price that is lower than the index for 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 transport 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 expenses.

For our product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC Topic 606 which states the Company is not required to disclose the transaction price allocated to the remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, monthly sales of a product generally represent a separate performance obligation; therefore, future commodity volumes to be delivered and sold are wholly unsatisfied and disclosure of the transaction price allocated to such unsatisfied performance obligations is not required.

Business Combinations. We utilize the acquisition method to account for acquisitions of businesses. Pursuant to the acquisition method, we allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. The purchase price allocations are based upon appraisals, discounted cash flows and estimates by management, which are Level 3 inputs. When appropriate, we review recent comparable purchases and sales of crude oil and natural gas properties within the same regions and use that data as a basis for fair market value; for example, the amount at which a willing buyer and seller would enter into an exchange for such properties.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved developed producing, proved developed non-producing, proved undeveloped and unproved crude oil and natural gas properties. To estimate the fair value of these properties as part of acquisition accounting, we estimate the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of reserves volumes, future operating and development costs, future commodity prices, and a market based weighted average cost of capital rate. The market based weighted average cost of capital rate is subject to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, we reduce the discounted future net revenues of probable and possible reserves by additional risk-weighting factors. Additionally, for acquisitions with significant unproved properties, we complete an analysis of recent comparable purchased properties to determine an estimation of fair value.

If applicable, we record deferred taxes for any differences between the assigned values and tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Acreage Exchanges. From time to time, we enter into acreage exchanges in order to consolidate our core acreage positions, enabling us to have more control over the timing of development activities, achieve higher working interests and provide us the ability to drill longer lateral length wells within those core areas. We account for our nonmonetary acreage exchanges in accordance with the guidance prescribed by Accounting Standards Codification 845, *Nonmonetary Transactions*. For those exchanges that lack commercial substance, we record the acreage received at the net carrying value of the acreage surrendered to obtain it. For those acreage exchanges that are deemed to have commercial substance, we record the acreage received at fair value, with a related gain or loss recognized in earnings, in accordance with Accounting Standards Codification 820, *Fair Value Measurement*.

Stock-Based Compensation. Stock-based compensation is recognized within our financial statements based on the grant-date fair value of the equity instrument awarded. Stock-based compensation expense is recognized in the financial statements on a straight-line basis over the requisite service period for the entire award and we account for forfeitures of stock-based compensation awards as they occur.

Fair Value of Assets and Liabilities. The Company follows the authoritative accounting guidance for measuring fair value of assets and liabilities in its financial statements. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity.

Leases. We determine if an arrangement is representative of a lease at contract inception. Right-of-use ("ROU") assets represent our right to use the underlying assets for the lease term and the corresponding lease liabilities represent our obligations to make lease payments arising from the leases. Operating and finance lease ROU assets and liabilities are recognized at the commencement date based on the present value of the expected lease payments over the lease term. As most of our leases do not provide an implicit interest rate, we utilize our incremental borrowing rate based on information available at the commencement date in determining the present value of lease payments. Subsequent measurement, as well as presentation of expenses and cash flows, will depend upon the classification of the lease as either a finance or operating lease. Terms of our leases include options to extend or terminate the lease only when we can ascertain that it is reasonably certain we will exercise that option. Leases with an initial term of one year or less are not recorded on the consolidated balance sheets.

We apply the practical expedient that permits combining lease and non-lease components in a contract and accounting for the combination as a single lease component (applied by asset class).

NOTE 3 - PENDING ACQUISITION

On February 26, 2022, we entered into a definitive purchase agreement under which we will acquire Great Western Petroleum, LLC ("Great Western") for approximately $1.3 billion, inclusive of Great Western's net debt (the "Great Western Acquisition"). Great Western is an independent oil and gas company focused on the exploration, production and development of crude oil and natural gas in Colorado. The purchase consideration for the Great Western Acquisition will be made through the transfer of approximately 4.0 million shares of our common stock and approximately $543 million in cash, pursuant to the

Membership Interest Purchase Agreement that we entered into with Great Western ("Acquisition Agreement"). We expect the Great Western Acquisition to be completed in the second quarter of 2022, subject to certain customary closing conditions, including diligence.

NOTE 4 - BUSINESS COMBINATION

In January 2020, we merged with SRC Energy, Inc. ("SRC") in a transaction valued at $1.7 billion, inclusive of SRC's net debt (the "SRC Acquisition"). SRC was an independent oil and natural gas company engaged in the exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in Weld County, Colorado. The acquisition added approximately 83,000 net acres which are located on large, contiguous acreage blocks in the core of the Wattenberg Field.

Upon closing, we issued approximately 38.9 million shares of our common stock to SRC shareholders and holders of SRC equity awards, reflecting the issuance of 0.158 of a share of our common stock in exchange for each outstanding share of SRC common stock and the cancellation of outstanding SRC equity awards pursuant to the terms of the merger agreement that we entered into with SRC. We finalized the purchase price allocation on December 31, 2020, and we recognized total transaction costs of $19.9 million for the year ended December 31, 2020.

The following table details our final purchase price, valuation and allocation of the purchase price to the assets acquired and liabilities assumed as a result of the SRC Acquisition:

	(in thousands)
Consideration:	
Cash	$ 40
Retirement of seller's credit facility	166,238
Total cash consideration	166,278
Common stock issued	1,009,015
Shares withheld in lieu of taxes	6,299
Total consideration	$ 1,181,592
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Assets acquired:	
Current assets	$ 145,792
Properties and equipment, net - proved	1,613,674
Properties and equipment, net - unproved	109,615
Properties and equipment, net - other	16,242
Deferred tax asset	189,311
Other assets	11,810
Total assets acquired	$ 2,086,444
Liabilities assumed:	
Current liabilities	$ (253,967)
Senior notes	(555,500)
Asset retirement obligations	(42,417)
Other liabilities	(52,968)
Total liabilities assumed	(904,852)
Total identifiable net assets acquired	$ 1,181,592

This acquisition was accounted for under the acquisition method of accounting for business combinations. Accordingly, we conducted assessments of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition were expensed as incurred. The fair value 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 10 percent. These inputs require significant judgments and estimates by management at the time of the valuation.

The results of operations for the SRC Acquisition since the closing date have been included on our consolidated financial statements for the year ended December 31, 2020 and include approximately $320.9 million of total revenue, and $46.5 million of income from operations.

Pro Forma Information. The following unaudited pro forma financial information represents a summary of the consolidated results of operations for the years ended December 31, 2020, and 2019, assuming the acquisition had been completed as of January 1, 2019. 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) the Company's common stock issued to convert SRC's outstanding shares of common stock and equity awards, (ii) the depletion of SRC's fair-valued proved oil and gas properties using the successful efforts method of accounting and (iii) the estimated tax impacts of the pro forma adjustments, if any. Additionally, pro forma earnings were adjusted to exclude acquisition-related costs incurred by the Company and SRC totaling approximately $38.0 million and $15.9 million for the years ended December 31, 2020 and 2019, respectively. 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.

	Year Ended December 31,	
	2020	2019
	(in thousands, except per share data)	
Total revenue	$ 1,361,051	$ 1,761,498
Net income (loss)	(695,663)	139,578
Earnings (loss) per share:		
Basic	$ (6.97)	$ 1.36
Diluted	(6.97)	1.35

NOTE 5 - 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:

	Year Ended December 31,		
Revenue by Commodity and Operating Region	**2021**	**2020**	**2019**
		(in thousands)	
Crude oil			
Wattenberg Field	$ 1,275,666	$ 668,948	$ 767,760
Delaware Basin	255,135	147,902	252,929
Total	1,530,801	816,850	1,020,689
Natural gas			
Wattenberg Field	458,870	171,755	137,143
Delaware Basin	60,733	6,997	13,877
Total	519,603	178,752	151,020
NGLs			
Wattenberg Field	428,570	128,126	94,347
Delaware Basin	73,584	28,827	41,219
Total	502,154	156,953	135,566
Crude oil, natural gas and NGLs			
Wattenberg Field	2,163,106	968,829	999,250
Delaware Basin	389,452	183,726	308,025
Total	$ 2,552,558	$ 1,152,555	$ 1,307,275

Contract Assets. Contract assets include material contributions in aid of construction, which are common in purchase and processing agreements with midstream service providers that are our customers. The intent of the payments is primarily to reimburse the customer for actual costs incurred related to the construction of its gathering and processing infrastructure. Contract assets are included in other assets on the consolidated balance sheets. The contract assets are amortized as a reduction to crude oil, natural gas and NGLs sales revenue during the periods in which the related production is transferred to the customer.

The following table presents the changes in carrying amounts of the contract assets associated with our crude oil, natural gas and NGLs sales revenue for the periods presented:

	December 31,	
	2021	**2020**
	(in thousands)	
Beginning balance	$ 25,872	$ 11,494
Additions (Net reduction to additions previously recognized)	(7,705)	16,739
Amortized as a reduction to crude oil, natural gas and NGLs sales	(2,695)	(2,361)
Ending balance	$ 15,472	$ 25,872

NOTE 6 - 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:

		December 31, 2021			December 31, 2020		
	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	$ —	$ 17,909	$ 17,909	$ 36,580	$ 12,289	$ 48,869
Non-current	Fair value of derivatives	605	14,572	15,177	315	9,250	9,565
Total		$ 605	$ 32,481	$ 33,086	$ 36,895	$ 21,539	$ 58,434
Derivative liabilities							
Current	Fair value of derivatives	$ (230,695)	$ (74,175)	$ (304,870)	$ (76,420)	$ (21,732)	$ (98,152)
Non-current	Fair value of derivatives	(74,715)	(20,846)	(95,561)	(28,125)	(8,234)	(36,359)
Total		$ (305,410)	$ (95,021)	$ (400,431)	$ (104,545)	$ (29,966)	$ (134,511)

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

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Fair value of Level 3 instruments, net asset (liability) beginning of period	$ (8,427)	$ 8,414	$ 58,329
Changes in fair value included in consolidated statements of operations line item:			
Commodity price risk management gain (loss), net	(206,109)	37,821	(41,749)
Settlements included in consolidated statements of operations line items:			
Commodity price risk management gain (loss), net	151,996	(54,662)	(8,166)
Fair value of Level 3 instruments, net asset (liability) end of period	$ (62,540)	$ (8,427)	$ 8,414
Net change in fair value of Level 3 unsettled derivatives included in consolidated statements of operations line item:			
Commodity price risk management gain (loss), net	$ (35,108)	$ —	$ (22,694)
Total	$ (35,108)	$ —	$ (22,694)

The significant unobservable input used in the fair value measurement of our derivative contracts is the implied volatility curve, which is provided by a third-party vendor. 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 not elected 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 and convertible notes as of the dates indicated:

		December 31,			
		2021		2020	
	Nominal Interest	Estimated Fair Value	Percent of Par	Estimated Fair Value	Percent of Par
		(in millions)		*(in millions)*	
2021 Convertible Notes [1]	1.125 %	$ —	— %	$ 196.2	98.1 %
2024 Senior Notes	6.125 %	202.8	101.4 %	410.8	102.7 %
2025 Senior Notes [2]	6.25 %	—	— %	102.8	100.5 %
2026 Senior Notes	5.75 %	775.5	103.4 %	775.5	103.4 %

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(1) Our 2021 Convertible Notes were redeemed and retired on September 15, 2021.
(2) Our 2025 Senior Notes were redeemed and retired on December 1, 2021.

NOTE 7 - 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 oil and 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 December 31, 2021, we had derivative instruments in place for a portion of our anticipated production in 2022 through 2024. 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.

As of December 31, 2021 and 2020, our derivative instruments were comprised of fixed-price swaps, collars and basis protection swaps.

- Fixed-price swaps are arrangements that guarantee a fixed price. If the index price is below the fixed contract price, we receive the market price from the purchaser and receive the difference between the index price and the fixed contract price from the counterparty. If the index price is above the fixed contract price, we receive the market price from the purchaser and pay the difference between the index price and the fixed contract price to the counterparty;

- Collars contain a fixed floor price (put) and ceiling price (call). If the index price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and index price from the counterparty. If the index price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and index price to the counterparty. If the index price is between the put and call strike price, no payments are due to or from the counterparty;

- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For basis protection swaps, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract.

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

Consolidated Statements of Operations Line Item	Year Ended December 31, 2021	2020	2019
	(in thousands)		
Commodity price risk management gain (loss), net			
Net settlements	$ (410,188)	$ 279,271	$ (17,598)
Net change in fair value of unsettled derivatives	(291,268)	(99,001)	(145,246)
Total commodity price risk management gain (loss), net	$ (701,456)	$ 180,270	$ (162,844)

Commodity Derivative Contracts. As of December 31, 2021, we had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is presented:

	Collars			Fixed-Price Swaps		
		Weighted Average Contract Price				
Commodity/ Index/ Maturity Period	**Quantity** *(Crude oil - MBbls Natural Gas - BBtu)*	**Floors**	**Ceilings**	**Quantity** *(Crude Oil - MBbls Gas and Basis- BBtu)*	**Weighted Average Contract Price**	**Fair Value December 31, 2021** *(in thousands)*
Crude Oil						
NYMEX						
2022	5,472	$ 53.18	$ 67.33	6,744	$ 44.42	$ (235,146)
2023	2,775	55.00	70.00	5,502	56.83	(58,299)
2024	225	55.00	75.12	1,500	61.27	(2,276)
Total Crude Oil	8,472			13,746		(295,721)
Natural Gas						
NYMEX						
2022	35,460	3.14	4.78	33,600	2.70	(41,165)
2023	3,000	3.00	4.42	30,398	2.68	(19,171)
Total Natural Gas	38,460			63,998		(60,336)
Basis Protection - Natural Gas						
CIG						
2022	—	—	—	69,060	(0.25)	(10,650)
2023	—	—	—	29,438	(0.27)	(638)
Total Basis Protection - Natural Gas	—			98,498		(11,288)
Commodity Derivatives Fair Value						$ (367,345)

Subsequent to December 31, 2021, we entered into the following commodity derivative positions covering our crude oil and natural gas production:

	Collars			Fixed-Price Swaps	
		Weighted Average Contract Price			
Commodity/ Index/ Maturity Period	Quantity *(Crude oil - MBbls Natural Gas - BBtu)*	Floors	Ceilings	Quantity *(Crude oil - MBbls Natural Gas - BBtu)*	Weighted-Average Contract Price
Crude Oil - NYMEX					
2023	1,050	$ 55.00	$ 79.14	—	$ —
2024	—	—	—	2,208	70.25
Natural Gas - NYMEX					
2023	12,060	3.08	4.35	—	—
Natural Gas Basis Protection - CIG					
2023	—	—	—	12,060	(0.29)

Effect of Derivative Instruments on the Consolidated Balance Sheet. The balance sheet line items and fair value amounts of our derivative instruments are disclosed in *Note 6 - 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 consolidated balance sheets.

The following table reflects the impact of netting agreements on gross derivative assets and liabilities:

	Total Gross Amount Presented on the Balance Sheet	Effect of Master Netting Agreements	Total Net Amount
As of December 31, 2021		*(in thousands)*	
Derivative asset instruments, at fair value	$ 33,086	$ (33,086)	$ —
Derivative liability instruments, at fair value	$ 400,431	$ (33,086)	$ 367,345
As of December 31, 2020			
Derivative asset instruments, at fair value	$ 58,434	$ (39,691)	$ 18,743
Derivative liability instruments, at fair value	$ 134,511	$ (39,691)	$ 94,820

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 December 31, 2021; however, this determination may change.

NOTE 8 - 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:

	December 31, 2021	December 31, 2020
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$ 8,310,018	$ 7,523,639
Unproved	306,181	350,677
Total crude oil and natural gas properties	8,616,199	7,874,316
Equipment and other	63,099	65,027
Land and buildings	19,928	24,299
Construction in progress	371,968	523,550
Properties and equipment, at cost	9,071,194	8,487,192
Accumulated DD&A	(4,256,329)	(3,627,993)
Properties and equipment, net	$ 4,814,865	$ 4,859,199

Impairment of Oil and Gas Properties. The following table presents impairment charges recorded for properties and equipment for the periods presented:

	Year Ended December 31, 2021	2020	2019
		(in thousands)	
Impairment of proved and unproved properties	$ 402	$ 881,238	$ 10,599
Impairment of infrastructure and other	—	1,155	27,937
Total impairment of properties and equipment	$ 402	$ 882,393	$ 38,536

Oil and Gas Properties.

In the first quarter of 2020, the significant decline in crude oil prices in addition to the ongoing effects of the COVID-19 pandemic were considered a triggering event that required us to assess our crude oil and natural gas properties for possible impairment. As a result of our assessment, we recorded impairment expense of $881.1 million to our proved and unproved properties. During the year ended December 31, 2021, there were no significant impairments recognized.

Proved Properties. Of the total impairment expense recognized in 2020, approximately $753.0 million was related to our Delaware Basin proved properties. These impairment charges represented the amount by which the carrying value of the crude oil and natural gas properties exceeded the estimated fair value. We estimated the fair value of proved crude oil and natural gas properties using valuation techniques that convert future cash flows to a single discounted amount, a Level 3 input. Significant inputs and assumptions to the valuation of proved crude oil and natural gas properties include estimates of future production volumes, future operating and development costs, future commodity prices, and a discount rate of 17 percent, which was based on a weighted average cost of capital for the area where the assets are located. There were no impairment charges recognized related to our proved properties during the year ended December 31, 2019.

Unproved Properties. We recognized approximately $127.3 million of impairment charges for our unproved properties in the Delaware Basin in 2020. These impairment charges were recognized based on the fair value of the properties, a Level 3 input. The fair value is estimated based on a review of our current drilling plans, estimated future cash flows for probable well locations and expected future lease expirations, primarily in areas where we have no development plans.

During the year ended December 31, 2019, we recorded impairment charges totaling $10.6 million related to the divestiture of unproved leaseholds and then-current and anticipated near-term leasehold expirations within our non-focus areas of the Delaware Basin that we determined not to develop.

Other Property and Equipment Impairment. During the year ended December 31, 2019, we recorded impairments of $27.9 million related to certain midstream facility infrastructure in the Delaware Basin. Upon the divestiture of certain midstream assets, it was determined that the net book value of these assets was not recoverable.

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	2020	2019
	(in thousands, except for number of wells)		
Beginning balance	$ 7,459	$ 16,078	$ 12,188
Additions to capitalized exploratory well costs pending the determination of proved reserves	5,902	11,770	31,901
Reclassifications to proved properties	(13,361)	(20,389)	(28,011)
Ending balance	$ —	$ 7,459	$ 16,078
Number of wells pending determination at period-end	—	2	4

As of December 31, 2020, our net capitalized exploratory well costs that have been capitalized for a period greater than one year was $7.5 million, which consists of the entire balance of our suspended well costs and relates to two gross suspended wells associated with two projects. During the year ended December 31, 2021, both exploratory wells were determined to be successful producing wells and were reclassified into proved properties. We have no remaining exploratory wells pending determination as of December 31, 2021.

NOTE 9 - 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:

	December 31,	
	2021	2020
	(in thousands)	
Crude oil, natural gas and NGLs sales	$ 368,991	$ 178,147
Joint interest billings	24,860	35,396
Other	10,809	37,471
Allowance for doubtful accounts	(6,055)	(6,763)
Accounts receivable, net	$ 398,605	$ 244,251

The Company’s accounts receivable consist mainly of receivables from (i) crude oil, natural gas and NGLs purchasers, (ii) joint interest owners in the properties we operate and (iii) derivative counterparties. Most payments for production are received within two months after the production date. For receivables from joint interest owners, we typically have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

Credit and Concentration Risk. Inherent to our industry is the concentration of crude oil, natural gas and NGLs sales to a limited number of customers. This concentration has the potential to impact our overall exposure to credit risk in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions.

Given the liquidity in the market for the sale of hydrocarbons, we believe that the loss of any single purchaser, or the aggregate loss of several purchasers, could be managed by selling to alternative purchasers in our operating areas. The following major customers accounted for 10 percent or more of our total crude oil, natural gas, and NGLs sales for at least one of the periods presented:

	Year Ended December 31,		
	2021	2020	2019
Major customer #1	32 %	31 %	20 %
Major customer #2	11 %	16 %	16 %
Major customer #3	10 %	13 %	11 %
Major customer #4	9 %	17 %	17 %

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

	December 31,	
	2021	2020
	(in thousands)	
Employee benefits	$ 29,319	$ 23,304
Asset retirement obligations	32,146	33,933
Environmental expenses	11,942	10,139
Operating and finance leases	7,197	7,986
Other	10,805	6,353
Other accrued expenses	$ 91,409	$ 81,715

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

	December 31,	
	2021	2020
	(in thousands)	
Deferred midstream gathering credits	$ 159,788	$ 168,478
Deferred oil gathering credits	16,080	18,090
Production taxes	131,865	65,592
Operating and finance leases	6,274	10,763
Other	762	1,111
Other liabilities	$ 314,769	$ 264,034

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.

Deferred Oil Gathering Credits. In 2018, we entered into an agreement that dedicates crude oil from the majority of our Wattenberg Field acreage to the midstream provider's gathering lines and extends the term of the agreement through December 2029. The acreage dedication agreement resulted in an initial cash receipt and is 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 consolidated statements of operations for the periods indicated:

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Crude oil, natural gas and NGLs sales	$ —	$ 1,013
Transportation, gathering and processing expense	7,317	5,618
Lease operating expense	2,422	2,015

NOTE 10 - LONG-TERM DEBT

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $7.9 million and $17.8 million as of December 31, 2021 and December 31, 2020, respectively, consists of the following:

	December 31,	
	2021	2020
	(in thousands)	
Revolving credit facility due November 2026	$ —	$ 168,000
1.125% Convertible Notes due September 2021	—	193,014
6.125% Senior Notes due September 2024	198,674	396,368
6.25% Senior Notes due December 2025	—	103,204
5.75% Senior Notes due May 2026	743,410	741,976
Total debt, net of unamortized discount, premium and debt issuance costs	942,084	1,602,562
Less: Current portion of long-term debt	—	193,014
Total long-term debt	$ 942,084	$ 1,409,548

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 December 31, 2021, we had a borrowing base of $2.4 billion, an elected commitment of $1.5 billion and availability under our revolving credit facility of $1.5 billion, net of $19.9 million of letters of credit outstanding.

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 December 31, 2021, the applicable interest margin is 0.75 percent for the alternate base rate option or 1.75 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 3.50:1.0; (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 December 31, 2021, we were in compliance with all covenants related to our revolving credit facility.

As of December 31, 2021 and 2020, debt issuance costs related to our revolving credit facility were $16.9 million and $8.1 million, respectively, and are included in other assets on our consolidated balance sheets.

Senior Notes and Convertible 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 December 31, 2021:

	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.

Our wholly-owned subsidiary, PDC Permian, Inc., is a guarantor of our obligations under the 2024 Senior Notes and the 2026 Senior Notes (collectively, the "Senior Notes").

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 all of our assets; and create unrestricted subsidiaries. As of December 31, 2021, we were in compliance with all covenants and all restricted payment provisions related to our Senior Notes.

Retirement of Convertible Notes. On September 15, 2021, we redeemed and retired our 2021 Convertible Notes with a cash payment for the principal amount of $200 million plus accrued and unpaid interest.

Early Retirement of Senior Notes. In November 2021, we redeemed $200 million in aggregate principal amount of our 2024 Senior Notes at a redemption price of 101.531 percent of the principal plus accrued and unpaid interest, leaving an aggregate principal amount outstanding of $200 million. Additionally, in December 2021, we redeemed the remaining $102.3 million principal amount of our 2025 Senior Notes at a redemption price of 103.125 percent of the principal plus accrued and unpaid interest. We recognized an aggregate loss on extinguishment of $6.9 million from the partial redemption of our 2024 Senior Notes and retirement of our 2025 Senior Notes. The loss on extinguishment was presented as part of interest expense, net on the consolidated statement of operations.

NOTE 11 - 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 five years. The vehicle leases include an option to renew on a month-to-month basis after the primary term. Lease payments associated with vehicle leases also include a contractually stated residual value guarantee.

The following table presents the components of lease costs for the periods presented:

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Operating lease costs [1]	$ 6,125	$ 7,983
Finance lease costs:		
Amortization of ROU assets	1,752	1,812
Interest on lease liabilities	164	179
Total finance lease costs	1,916	1,991
Short-term lease costs [1]	203,361	193,756
Total lease costs	$ 211,402	$ 203,730

(1) The majority of our operating leases relate to the operation or completion of our wells. Therefore, the lease costs presented in the table above represent the total gross costs we incur, which are not comparable to our net costs recorded to the consolidated statements of operations, consolidated statements of cash flows or capitalized in the consolidated balance sheets, as amounts therein are reflected net of amounts billed to working interest partners.

Our operating lease costs are recorded in lease operating expenses or general and administrative expense and our finance lease costs are recorded in DD&A expense and interest expense. 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 and other information regarding our leases as of the dates indicated:

	Consolidated Balance Sheet Line Item	December 31, 2021	December 31, 2020
		(in thousands)	
Operating lease ROU assets	Other assets	$ 7,630	$ 11,722
Finance lease ROU assets	Properties and equipment, net	$ 3,483	$ 3,189
Total ROU assets		$ 11,113	$ 14,911
Operating lease obligation - short-term	Other accrued expenses	5,937	6,520
Operating lease obligation - long-term	Other liabilities	4,044	9,061
Finance lease obligation - short-term	Other accrued expenses	1,260	1,466
Finance lease obligation - long-term	Other liabilities	2,230	1,702
Total lease liabilities		$ 13,471	$ 18,749
Weighted average remaining lease term (years)		2.8	3.0
Weighted average discount rate		4.8 %	4.8 %

Maturity of lease liabilities by year and in the aggregate, under operating and financing leases with terms of one year or more, as of December 31, 2021 consist of the following:

	Operating Leases	Finance Leases	Total
		(in thousands)	
2022	$ 6,214	$ 1,378	$ 7,592
2023	1,767	1,119	2,886
2024	950	612	1,562
2025	950	473	1,423
2026	747	148	895
Total lease payments	10,628	3,730	14,358
Less: Interest and discount	(647)	(240)	(887)
Present value of lease liabilities	$ 9,981	$ 3,490	$ 13,471

In January 2022, we entered into a 11-year lease agreement for an office space expected to commence in March 2022 with aggregate lease payments of approximately $32 million.

NOTE 12 - 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 periods presented:

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Beginning balance	$ 166,570	$ 127,251
Obligations incurred with development activities and other	4,750	6,494
Obligations incurred with acquisition	—	47,673
Accretion expense	12,086	10,072
Revisions in estimated cash flows	10,609	4,742
Obligations discharged with asset retirements and divestitures	(34,343)	(29,662)
Asset retirement obligations at end of period	159,672	166,570
Current portion[1]	(32,146)	(33,933)
Long-term portion	$ 127,526	$ 132,637

(1) The current portion of the asset retirement obligation is included in other accrued expenses on our 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 that time. 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 13 - COMMITMENTS AND CONTINGENCIES

The following table presents our firm transportation, sales and processing, water delivery and disposal and purchase commitments:

	Year Ending December 31,							
	2022	2023	2024	2025	2026	Thereafter	Total	Expiration Date for Thereafter
Natural gas (MMcf)	82,264	82,264	82,489	70,296	37,029	73,050	427,392	December 31, 2030
Crude oil (MBbls)	23,360	19,685	9,882	9,855	6,561	—	69,343	
Water (MBbls)	6,207	6,207	6,224	—	—	—	18,638	
Purchase obligation (Tons)	110,000	300,000	—				410,000	
Dollar commitment *(in thousands)*	$ 153,857	$ 157,370	$ 92,247	$ 77,491	$ 39,631	$ 37,811	$ 558,407	

Firm Transportation and Processing Agreements. We enter into contracts that provide firm transportation and processing on pipeline systems through which we transport or sell crude oil and natural gas. Satisfaction of the volume requirements includes volumes produced by us and purchased from third parties and produced by other third-party working, royalty and overriding royalty interest owners, whose volumes we market on their behalf. Our consolidated statements of operations reflect our share of these firm transportation and processing costs. These contracts require us to pay these transportation and processing charges whether or not the required volumes are delivered. We may from time to time find ourselves unable to market our commodities at prices acceptable to us, or at all, which could cause us to be unable to meet these obligations. In such cases, we may be subject to fees, minimum margins or other payments. Payments related to our long-term transportation and processing agreements, net of interests, were $31.3 million, $21.4 million, and $27.3 million for the years ended December 31, 2021, 2020, and 2019, respectively.

Facilities Expansion Agreements. We entered into two facilities expansion agreements with our primary midstream provider to expand and improve its natural gas gathering pipelines and processing facilities in the Wattenberg Field. The midstream provider completed and turned on line two 200 MMcfd cryogenic plants in 2018 and 2019. Both agreements require baseline volume commitments and aggregate incremental wellhead volume commitments of 98.1 MMcfd and 77.3 MMcfd for the first and second agreements, respectively. We may be required to pay shortfall fees for any volumes under aggregate incremental commitments. Any shortfall in these volume commitments may be offset by other producers’ volumes sold to the midstream provider that are greater than a certain total baseline volume. We are also required for the first three years of the contracts to guarantee a certain target profit margin to the midstream provider on these incremental volumes. The actual net shortfall in target profit margin incurred, which we guaranteed to our midstream provider, was included as part of contract assets as part of other assets on the consolidated balance sheets.

Firm sales agreement. As of December 31, 2021 we had a firm sales agreement with an integrated marketing company for our crude oil production in the Delaware Basin through 2023. This agreement is expected to provide price diversification through realization of export market pricing via a Corpus Christi terminal and exposure to Brent-weighted prices. This agreement does not require physical delivery of the minimum volumes of crude oil over the contractual term. However, if we do not sell and deliver at least the minimum contract volume pursuant to the agreement, we are required to pay transportation reservation charges related to the undelivered volume. For the years ended December 31, 2021 and 2020, we did not incur material transportation reservation charges under this agreement.

Purchase Obligation. As of December 31, 2021 we had a purchase agreement to buy a minimum volume of frac sand at a fixed sales price effective June 2022 through December 2023. The obligation included in the table above represents the minimum financial commitments pursuant to the terms of the agreement as of December 31, 2021.

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 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 14 - COMMON STOCK

Stock-Based Compensation Plans

2018 Equity Incentive Plan. In 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”) from 1,800,000 to 7,050,000 shares. The 2018 Plan expires in March 2028. The capital stock available for issuance under the 2018 Plan consists of shares of the Company’s authorized but unissued common stock or previously issued common stock that has been reacquired by the Company. Additionally, to the extent that an award under the 2018 Plan, in whole or in part, is canceled, expired, forfeited, settled in cash or otherwise terminated without delivery of shares, such shares remain available for issuance. Any shares withheld for taxes cannot be recycled under this plan. Awards may be issued in the form of options, stock appreciation rights (“SARs”), restricted stock, restricted stock units (“RSUs”), performance stock units (“PSUs”) and other stock-based awards. Awards may vest over periods of continued service or upon the satisfaction of performance conditions set at the discretion of the Compensation Committee of our board of directors (the “Compensation Committee”), with a minimum one-year vesting period applicable to most awards. With regard to SARs and options, awards have a maximum exercisable period of ten years. As of December 31, 2021, there were 4,177,611 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 may 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 December 31, 2021, there were 314,413 shares available for grant under the 2010 Plan.

2015 SRC Equity Incentive Plan. Pursuant to the closing of the SRC Acquisition, SRC granted PSUs to certain SRC executives (the “SRC PSUs”) under the 2015 SRC Equity Incentive Plan (the “2015 SRC Plan”). The SRC PSUs were converted into 155,928 PDC PSUs and remained subject to the same terms and conditions (including performance-vesting terms) that applied immediately prior to the closing of the SRC Acquisition. As of December 31, 2021, all converted SRC PSUs vested and there were no shares available for grant under the 2015 SRC 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:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
General and administrative expense	$ 21,830	$ 21,182	$ 22,754
Lease operating expense	1,193	1,018	1,083
Total stock-based compensation expense	$ 23,023	$ 22,200	$ 23,837

Restricted Stock Units

The Company grants to executive officers and employees time-based RSUs, which vest ratably over a three-year service period. The fair value of these time-based RSUs is based on the market price of our common stock on the grant date and is recognized ratably over the requisite service period. The time-based RSUs generally vest ratably on each anniversary following the grant date provided that a participant is continuously employed.

The following table presents the changes in non-vested time-based RSUs to eligible employees, including executive officers, during the year ended December 31, 2021:

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at beginning of period	1,150,970	$ 20.14
Granted	657,972	33.64
Vested	(547,985)	24.86
Forfeited	(95,770)	22.74
Non-vested at end of period	1,165,187	25.33

The weighted average grant-date fair value of restricted stock units was $33.64, $11.98 and $40.34 for the years ended December 31, 2021, 2020 and 2019, respectively. The total grant-date fair value of restricted stock units that vested for the years ended December 31, 2021, 2020 and 2019 was $13.6 million, $20.4 million and $16.3 million, respectively. Total compensation cost related to non-vested time-based awards and not yet recognized on the consolidated statements of operations as of December 31, 2021 was $18.2 million. This cost is expected to be recognized over a weighted average period of 1.6 years.

Performance Stock Units

The Company grants to certain executive officers PSUs which are subject to market-based vesting criteria as well as a three-year service period. The market-based shares vest if the participant is continuously employed throughout the performance period and the market-based performance measure is achieved. The fair value of the market-based PSUs is amortized ratably over the requisite service period. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

The Compensation Committee awarded a total of 207,655 market-based PSUs to our executive officers during 2021. 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, 2023, 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.

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:

	Year Ended December 31,		
	2021	2020	2019
Expected term of award (in years)	3	3	3
Risk-free interest rate	0.2 %	1.4 %	2.5 %
Expected volatility	84.6 %	46.6 %	41.4 %
Weighted average grant-date fair value per share	$ 54.01	$ 33.52	$ 56.68

The expected term of the awards is based on the number of years from the grant date through the end of the performance period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant, extrapolated to approximate the life of the awards. The expected volatility was based on our common stock historical volatility, as well as that of our peer group.

The following table presents the change in non-vested market-based awards during the year ended December 31, 2021:

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at December 31, 2020	499,547	$ 38.66
Granted	207,655	54.01
Vested	(267,973)	43.10
Non-vested at December 31, 2021	439,229	43.21

The total grant-date fair value of performance stock units that vested in the years ended December 31, 2021, 2020 and 2019 was $11.6 million, $4.7 million and $2.0 million, respectively. On December 31, 2021, the service period lapsed on 112,045 performance stock units granted in 2019 and 155,928 SRC PSUs that earned 1.90 shares for each vested award resulting in 503,615 aggregate shares of common stock being issued in January 2022. Total compensation cost related to non-vested market-based awards not yet recognized on the consolidated statements of operations as of December 31, 2021 was $10.5 million. This cost is expected to be recognized over a weighted average period of 1.5 years.

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 December 31, 2021, no shares of preferred stock have been issued.

Stock Repurchase Program

In 2019, our board of directors approved the repurchase of up to $200 million of our outstanding common stock (the "Stock Repurchase Program"). Effective upon the closing of the SRC Acquisition, our board of directors approved an increase and extension to the Stock Repurchase Program from $200 million to $525 million. Repurchases under the Stock Repurchase Program can be made in open markets at our discretion and in compliance with safe harbor provisions, or in privately negotiated transactions. The Stock Repurchase Program does not require any specific number of shares to be acquired, is subject to market conditions and can be modified or discontinued by the board of directors at any time. Pursuant to the Stock Repurchase Program, we repurchased 3.8 million and 1.3 million shares of outstanding common stock at a cost of $159.5 million and $23.8 million during the years ended December 31, 2021 and 2020, respectively. We suspended the program in 2020 due to adverse market conditions but reinstated it in 2021. As of December 31, 2021, $187.3 million remained available under the program for repurchases of our outstanding common stock. In February 2022, our board of directors increased the size of the program to $1.25 billion and extended it through December 31, 2023. The Stock Repurchase Program is being implemented at the discretion of our board of directors and may be suspended, modified, extended or discontinued by our board of directors at any time.

Dividends

In the second quarter of 2021, our board of directors commenced the declaration and payment of quarterly cash dividends of $0.12 per share of our outstanding common stock. In December 2021, our board of directors declared and paid a special dividend of $0.50 per share of our outstanding common stock in addition to the fourth quarter dividend. For the year ended December 31, 2021, our dividends paid totaled $0.86 per share of common stock or $83.6 million. All RSUs and PSUs receive a dividend equivalent per unit, recognized as a liability included in other liabilities on the consolidated balance sheets, until the recipients receive the equivalents upon vesting. Dividends declared were recorded as a reduction of additional paid-in capital as there were no retained earnings as of the date of declaration. 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 15 - INCOME TAXES

The table below presents the components of our provision for income tax (expense) benefit for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Current:			
Federal	$ —	$ 1,592	$ 1,366
State	(200)	(220)	(300)
Total current income tax benefit	(200)	1,372	1,066
Deferred:			
Federal	(23,790)	5,460	4,507
State	(2,593)	1,070	(2,251)
Total deferred income tax (expense) benefit	(26,383)	6,530	2,256
Income tax (expense) benefit	$ (26,583)	$ 7,902	$ 3,322

The following table presents a reconciliation of the federal statutory rate to the effective tax rate related to our (expense) benefit for income taxes for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
Federal statutory tax rate	21.0 %	21.0 %	21.0 %
State income tax, net	3.2	3.0	3.6
Federal tax credits	—	—	(3.3)
Effect of state income tax rate changes	—	0.2	(6.4)
Change in valuation allowance	(19.8)	(22.1)	(0.6)
Non-deductible compensation	0.3	(0.6)	(5.0)
Non-deductible acquisition costs	—	(0.1)	(2.3)
Non-deductible government relations	0.1	(0.1)	(1.0)
Other non-deductible items	—	—	(0.5)
Other	—	(0.2)	—
Effective tax rate	4.8 %	1.1 %	5.5 %

The effective income tax rates for 2021 and 2020 were 4.8 percent and 1.1 percent on the respective pre-tax income or loss. The effective tax rates of 4.8 percent for 2021 and 1.1 percent for 2020 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 or loss due to the valuation allowance in effect at December 31, 2021 and 2020. The effective tax rate of 5.5 percent for 2019 differs from the statutory U.S. federal income tax rate of 21 percent due to state income taxes, non-deductible lobbying expenses, stock-based compensation and nondeductible officers' compensation.

Tax effects of temporary differences that give rise to significant portions of deferred tax assets and deferred tax liabilities as of the dates indicated:

	December 31,	
	2021	2020
	(in thousands)	
Deferred tax assets:		
Deferred compensation	$ 9,949	$ 10,472
Asset retirement obligations	38,274	39,371
Federal NOL carryforward	97,555	97,880
State NOL and tax credit carryforwards, net	20,266	21,034
Federal tax - credit carryforwards	3,059	3,059
Net change in fair value of unsettled commodity derivatives	88,053	18,351
Prepaid revenue	3,854	4,364
Other	4,454	5,741
Valuation allowance	(56,634)	(165,575)
Total gross deferred tax assets	208,830	34,697
Deferred tax liabilities:		
Properties and equipment	235,213	33,183
Convertible debt	—	1,514
Total gross deferred tax liabilities	235,213	34,697
Net deferred tax liability	$ 26,383	$ —

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 scheduled reversal of deferred tax liabilities, available taxes in carryback periods, tax planning strategies and projected future taxable income in making this assessment. The oil and gas property impairments and cumulative pre-tax losses were key considerations that led us to continue to provide a valuation allowance against our DTAs as of December 31, 2021 and 2020 since we cannot conclude that it is more likely than not that our DTAs will be fully realized in future periods.

Future events or new evidence which may lead us to conclude that it is more likely than not that our DTAs will be realized include, but are not limited to, cumulative historical pre-tax earnings, sustained or continued improvements in oil prices, and taxable events that could result from one or more transactions. Given recent improvements in oil and gas prices and improvements in our current earnings, we believe there is a reasonable possibility that, if oil and natural gas prices remain similar to December 31, 2021 pricing levels, sufficient positive evidence may become available within the next 12 months to allow us to reach a conclusion that all or a significant portion of the valuation allowance will no longer be needed. Release of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense in the period the release is recorded. However, the exact timing and amount of the valuation allowance release are subject to change based on the level of profitability that we actually achieve.

As of December 31, 2021, we have estimated net operating loss carryforwards ("NOLs") for federal income tax purposes of $464.5 million, of which $304 million was generated before January 1, 2018 and is not subject to the 80 percent limitation of taxable income. Such NOLs will expire beginning in 2033. In 2016, we acquired a federal NOL of $60.1 million as a component of our acquisition in the Delaware Basin that will begin to expire in 2033. Also, we acquired a federal NOL of $232.5 million as a component of the SRC Acquisition that will begin to expire in 2037. The federal NOLs acquired as part of the Delaware Basin acquisition and the SRC Acquisition are subject to an annual limitation of $15.1 million and $16.1 million, respectively, as both acquisitions constitute a change of ownership as defined under Internal Revenue Service ("IRS") Code Section 382.

As of December 31, 2021, we have state NOL carryforwards of $479.4 million that begin to expire in 2029 and state credit carryforwards of $3.9 million that begin to expire in 2022.

Unrecognized tax benefits and related accrued interest and penalties were immaterial for the three-year period ended December 31, 2021. As of December 31, 2021, there is no liability for unrecognized income tax benefits.

We are subject to the following material taxing jurisdictions: U.S., Colorado, West Virginia, and Texas. As of December 31, 2021, we are current with our income tax filings in all applicable state jurisdictions and are not currently under any state income tax examinations. We are open to federal and state tax audits until the applicable statutes of limitations expire, however, the ability for the tax authority to adjust the NOL will continue until three years after the NOL is utilized. The statute of limitations has expired for all federal and state returns filed for periods ending before 2016. The IRS has accepted our 2019 federal income tax return with no tax adjustments. The 2020 federal tax return is currently in the IRS Compliance Assurance Program (the "CAP Program") post-filing review process. 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. The statutes of limitations for most of our state tax jurisdictions are open for tax years after 2016.

NOTE 16 - 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 equity-based employee awards, convertible notes 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:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Weighted average common shares outstanding - basic	98,546	98,251	64,032
Dilutive effect of:			
RSUs and PSUs	1,596	—	—
Other equity-based awards	12	—	—
Weighted average common shares and equivalents outstanding - diluted	100,154	98,251	64,032

We reported a net loss for the years ended December 31, 2020 and 2019. As a result, our basic and diluted weighted average common shares outstanding were the same for those periods because the effect of the common share equivalents was anti-dilutive.

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:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:			
RSUs and PSUs	28	1,707	989
Other equity-based awards	116	229	302
Total anti-dilutive common share equivalents	144	1,936	1,291

When outstanding, the 2021 Convertible Notes gave the holders, at our election, the right to convert the aggregate principal amount into 2.3 million shares of our common stock at a conversion price of $85.39 per share. The 2021 Convertible Notes were not included in the diluted earnings per share calculation using the treasury stock method for any periods presented as the average market price of our common stock did not exceed the conversion price. Further, the 2021 Convertible Notes were fully retired on the maturity date, September 15, 2021.

NOTE 17 - SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Supplemental cash flow information			
Cash payments (receipts) for			
Interest, net of capitalized interest	$ 66,647	$ 75,506	$ 57,439
Income taxes	(1,057)	9	(1,167)
Non-cash investing and financing activities			
Change in accounts payable related to capital expenditures	519	(28,676)	(68,246)
Change in asset retirement obligations, with a corresponding change to crude oil and natural gas properties, net of disposals	11,673	54,984	29,533
Issuance of common stock for acquisition of crude oil and natural gas properties, net	—	1,009,015	—
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from operating leases	$ 7,603	$ 9,246	$ 5,301
Operating cash flows from finance leases	117	156	253
Right-of-use assets obtained in exchange for lease obligations			
Operating leases	$ 1,457	$ 4,305	$ 1,428
Finance leases	2,109	703	2,323

CRUDE OIL AND NATURAL GAS INFORMATION - UNAUDITED

Net Proved Reserves

All of our crude oil, natural gas and NGLs reserves are located in the United States. We utilize the services of independent petroleum engineers to estimate our crude oil, natural gas and NGLs reserves. As of December 31, 2021, 2020 and 2019 (as applicable), all of our estimates of proved reserves for the Wattenberg Field were based on reserve reports prepared by Ryder Scott and all of our estimates for proved reserves for the Delaware Basin were based on reserve reports prepared by NSAI. These reserve estimates have been prepared in compliance with guidelines established by the SEC and FASB. All of our proved undeveloped reserves conform to the SEC five-year rule requirement that they be scheduled to be drilled within five years of each location's initial booking date.

Reserve estimates are based on an unweighted arithmetic average of commodity prices during the preceding 12-month period, using the closing prices on the first day of each month, as required by the SEC. The table below presents the index prices for our estimated reserves, by commodity, as of the dates indicated:

	Average Benchmark Prices		
December 31,	**Crude Oil (per Bbl) (1)**	**Natural Gas (per MMBtu) (1)**	**NGLs (per Bbl) (2)**
2021	$ 66.56	$ 3.60	$ 66.56
2020	39.57	1.99	39.57
2019	55.69	2.58	55.69

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(1) Our benchmark indexes for crude oil and natural gas are WTI and Henry Hub, respectively.
(2) For NGLs, we use the NYMEX crude oil price as a reference for presentation purposes.

The netted back price used to estimate our reserves, by commodity, are presented below:

	Price Used to Estimate Reserves (1)		
December 31,	**Crude Oil (per Bbl)**	**Natural Gas (per MMBtu)**	**NGLs (per Bbl)**
2021	$ 65.37	$ 2.85	$ 24.96
2020	37.52	1.26	10.55
2019	52.63	1.50	12.21

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(1) These prices are based on the index prices and are net of basin differentials, transportation fees, contractual adjustments and Btu adjustments we experienced for the respective commodity, including consideration for contracts that are effective as of December 31, 2021.

The following tables present the changes in our estimated quantities of proved reserves:

	Crude Oil, Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved reserves, January 1, 2019	190,349	1,335,689	131,987	544,953
Revisions of previous estimates	25,875	328,290	31,559	112,147
Extensions, discoveries and other additions	1,056	10,262	1,519	4,285
Acquisition of reserves	553	4,558	448	1,761
Dispositions	(1,412)	(5,052)	(614)	(2,868)
Production	(19,166)	(115,950)	(10,923)	(49,414)
Proved reserves, December 31, 2019	197,255	1,557,797	153,976	610,864
Revisions of previous estimates	(41,089)	(272,243)	(14,774)	(101,237)
Extensions, discoveries and other additions	812	2,991	324	1,635
Acquisition of reserves	80,590	795,977	81,770	295,023
Dispositions	(2,116)	(17,711)	(1,776)	(6,844)
Production	(23,720)	(165,637)	(17,042)	(68,368)
Proved reserves, December 31, 2020	211,732	1,901,174	202,478	731,073
Revisions of previous estimates	22,651	408,540	54,634	145,375
Extensions, discoveries and other additions	528	1,584	168	960
Acquisition of reserves	1,616	24,174	2,469	8,113
Dispositions	—	—	—	—
Production	(22,682)	(175,747)	(19,360)	(71,333)
Proved reserves, December 31, 2021	213,845	2,159,725	240,389	814,188
Proved developed reserves, as of:				
December 31, 2019	66,211	554,234	55,411	213,994
December 31, 2020	86,330	860,877	91,702	321,512
December 31, 2021	97,420	1,088,700	120,132	399,002
Proved undeveloped reserves, as of:				
December 31, 2019	131,044	1,003,563	98,565	396,870
December 31, 2020	125,402	1,040,297	110,776	409,561
December 31, 2021	116,425	1,071,025	120,257	415,186

	Developed	Undeveloped	Total
		(MBoe)	
Proved reserves, January 1, 2019	179,535	365,418	544,953
Revisions of previous estimates	27,452	84,695	112,147
Extensions, discoveries and other additions	4,285	—	4,285
Acquisition of reserves	441	1,320	1,761
Dispositions	(474)	(2,394)	(2,868)
Production	(49,414)	—	(49,414)
Undeveloped reserves converted to developed	52,169	(52,169)	—
Proved reserves, December 31, 2019	213,994	396,870	610,864
Revisions of previous estimates	(8,634)	(92,603)	(101,237)
Extensions, discoveries and other additions	1,635	—	1,635
Acquisition of reserves	125,180	169,843	295,023
Dispositions	(2,487)	(4,357)	(6,844)
Production	(68,368)	—	(68,368)
Undeveloped reserves converted to developed	60,192	(60,192)	—
Proved reserves, December 31, 2020	321,512	409,561	731,073
Revisions of previous estimates	75,005	70,370	145,375
Extensions, discoveries and other additions	960	—	960
Acquisition of reserves	519	7,594	8,113
Dispositions	—	—	—
Production	(71,333)	—	(71,333)
Undeveloped reserves converted to developed	72,339	(72,339)	—
Proved reserves, December 31, 2021	399,002	415,186	814,188

2021 Activity. During 2021, we increased proved reserves by 83.1 MMBoe, or 11 percent, relative to December 31, 2020. The increase in proved reserves was primarily due to positive revisions resulting from our development activities and significant improvements in commodity prices during 2021, resulting in better economics. In 2021, we produced 71.3 MMBoe.

Revisions of Previous Estimates- Proved Developed Reserves. Proved developed reserves experienced a net positive revision of 75.0 MMBoe primarily due to (i) an increase of 44.3 MMBoe as a result of extended well lives directly correlated with the higher average prices for crude oil, natural gas and NGLs in 2021, (ii) a 24.9 MMBoe increase related to our operated and non-operated current year drilling activities not included within our five year development plan in the prior year, and (iii) an increase of 8.9 MMBoe related to performance revisions and other factors. The positive revisions were partially offset by a 3.1 MMBoe decrease associated with higher operating costs.

Revisions of Previous Estimates- PUDs. Net upward revisions to our previous PUD reserves estimates of 70.4 MMBoe were due to (i) a 166.5 MMBoe increase related to additional locations on proved acreage resulting from our 2021 development activities and changes to our drilling schedule resulting from state regulatory permitting process changes passed in 2021, (ii) a 8.6 MMBoe increase related to extended well lives directly correlated with the upward pricing adjustments due to improved average prices for crude oil, natural gas and NGLs in 2021, and (iii) 3.5 MMBoe related to performance revisions and other items. The positive revisions were partially offset by a 96.4 MMBoe downward revision primarily related to PUD locations that were reclassified to unproven reserves in our Wattenberg Field due to changes to our drilling schedule mainly resulting from state regulatory permitting process changes passed in 2021. Finally, a reduction of 11.8 MMBoe was recognized for locations no longer expected to be developed within five years of their initial recording in accordance with SEC rules.

Extensions, Discoveries and Other Additions- Proved Developed Reserves. Developed activity for 2021 included the addition of 1.0 MMBoe of developed reserves related to two gross newly turned-in-line wells in the Delaware Basin.

Acquisitions of Reserves- Proved Developed Reserves and PUDs. Proved developed and PUD reserves acquired primarily pertains to certain nonmonetary exchanges during 2021.

At December 31, 2020, we projected a PUD reserve conversion rate of 22 percent for 2021. During 2021, our actual conversion rate was 18 percent primarily due to a change in timing of completion activities in the Wattenberg Field. We converted 72.3 MMBoe of PUD reserves at December 31, 2020 to proved developed reserves as of December 31, 2021.

Based on economic conditions on December 31, 2021, our approved development plan provides for the development of our remaining PUD locations within five years of the date such reserves were initially recorded. The level of capital spending necessary to execute our development plan is consistent with our recent performance and updated drilling program.

2020 Activity. During 2020, we increased proved reserves by 120.2 MMBoe, or 20 percent, relative to December 31, 2019. The increase in proved reserves was primarily a result of our of the SRC Acquisition, partially offset by downward revisions of previous estimates. In 2020, we produced 68.4 MMBoe.

Revisions of Previous Estimates- Proved Developed Reserves. Proved developed reserves experienced a negative revision of 8.6 MMBoe primarily due to a decrease of 28.2 MMBoe as a result of lower average prices for crude oil, natural gas and NGLs for 2020. The negative revisions were partially offset by a 14.3 MMBoe increase associated with lower operating costs and a 5.3 MMBoe increase related to performance revisions and other items.

Revisions of Previous Estimates- PUDs. Net downward revisions to our previous PUD reserves estimates of 92.6 MMBoe were due to (i) 266.7 MMBoe related to PUD locations that were reclassified to unproven reserves due to drilling schedule changes, (ii) a reduction of 25.5 MMBoe was recognized for locations no longer expected to be developed within five years of their initial recording in accordance with SEC rules, and (iii) 11.3 MMBoe related to downward pricing adjustments due to lower average prices for crude oil, natural gas and NGLs for 2020. Drilling schedule changes resulted from PUD downgrades associated with lower realized prices and revised drilling plans following the completion of the SRC Acquisition. The negative revisions were partially offset by a 199.9 MMBoe increase related to additional locations on proved acreage resulting from our drilling plan and 11.0 MMBoe related to performance revisions and other items.

Extensions, Discoveries and Other Additions- Proved Developed Reserves. Developed activity for 2020 included the addition of 1.6 MMBoe of developed reserves related to two gross newly-drilled wells in the Delaware Basin.

Extensions, Discoveries and Other Additions- PUDs. There were no extensions, discoveries or other additions for PUD reserves during 2020.

Acquisitions of Reserves- Proved Developed Reserves. Proved developed reserves acquired primarily pertain to the SRC Acquisition completed in January 2020.

Acquisitions of Reserves- PUDs. Proved undeveloped reserves acquired primarily pertain to the SRC Acquisition completed in January 2020.

Dispositions- Proved Developed Reserves. Dispositions of 2.5 MMBoe were related to a divestiture and acreage surrendered in various acreage exchanges.

Dispositions- PUDs. Dispositions of 4.4 MMBoe were related to a divestiture and acreage surrendered in various acreage exchanges.

2019 Activity. During 2019, we increased proved reserves by 65.9 MMBoe, or 12 percent, relative to December 31, 2018. The increase in proved reserves was primarily a result of acreage exchange transactions and acquisitions in the Wattenberg Field and reserve additions on proved acreage resulting from our 2019 development activities. In 2019, we produced 49.4 MMBoe.

Revisions of Previous Estimates- Proved Developed Reserves. Proved developed reserves experienced a positive revision of 28.3 MMBoe reflecting improved performance revisions, decreased operating costs and other items. An additional increase of 10.2 MMBoe in developed reserves related to our current year drilling activities. These positive revisions were partially offset by a decrease of 11.0 MMBoe for decreases in prices for crude oil, natural gas and NGLs.

Revisions of Previous Estimates- PUDs. Upward revisions to our PUD reserves were related to an increase of 74.2 MMBoe reflecting additional locations on proven acreage resulting from our drilling plan, as well as improved performance revisions and other items, which resulted in further upward revisions of 28.9 MMBoe of PUD reserves. Partially offsetting these increases were negative revisions of 12.9 MMBoe due to drilling schedule changes and 5.5 MMBoe for decreases in prices for crude oil, natural gas and NGLs.

Extensions, Discoveries and Other Additions- Proved Developed Reserves. Developed additions for 2019 included the addition of 4.3 MMBoe of developed reserves related to three gross (three net) newly-drilled wells.

Extensions, Discoveries and Other Additions- PUDs. There were no extensions, discoveries or other additions for PUD reserves during 2019.

Acquisitions of Reserves- Proved Developed Reserves. Proved developed reserves acquired in various acreage exchanges and acquisitions were 0.4 MMBoe during 2019.

Acquisitions of Reserves- PUDs. We acquired 1.3 MMBoe of PUD reserves in 2019 in acreage exchanges and acquisitions.

Dispositions- Proved Developed Reserves. Dispositions of 0.5 MMBoe were related to a divestiture and acreage surrendered in various acreage exchanges.

Dispositions- PUDs. Dispositions of PUDs were 2.4 MMBoe were related to a divestiture and acreage surrendered in various acreage exchanges.

Results of Operations for Crude Oil and Natural Gas Producing Activities

The results of operations for crude oil and natural gas producing activities for the periods presented below:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Revenues:			
Crude oil, natural gas and NGLs sales	$ 2,552,558	$ 1,152,555	$ 1,307,275
Commodity price risk management gain (loss), net	(701,456)	180,270	(162,844)
	1,851,102	1,332,825	1,144,431
Expenses:			
Lease operating expenses	180,659	161,346	142,248
Production taxes	165,209	59,368	80,754
Transportation, gathering and processing expenses	100,403	77,835	46,353
Exploration expense	1,064	1,376	4,054
Depreciation, depletion and amortization	627,466	611,003	638,499
Accretion of asset retirement obligations	12,086	10,072	6,117
Impairment of properties and equipment	402	882,393	38,536
(Gain) loss on sale of properties and equipment	(912)	(724)	9,734
	1,086,377	1,802,669	966,295
Results of operations for crude oil and natural gas producing activities before provision for income taxes	764,725	(469,844)	178,136
Income tax (expense) benefit	(37,013)	5,168	(9,869)
Results of operations for crude oil and natural gas producing activities, excluding corporate overhead and interest costs	$ 727,712	$ (464,676)	$ 168,267

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including costs such as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance, production and severance taxes and associated administrative expenses. DD&A expense includes those costs associated with capitalized acquisition, exploration and development costs, but does not include the depreciation applicable to support equipment. The provision for income taxes is computed using effective statutory tax rates.

Costs Incurred in Crude Oil and Natural Gas Activities

Costs incurred in crude oil and natural gas property acquisition, exploration and development for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Acquisition of properties: (1)			
Proved properties	$ 1	$ 1,618,000	$ 16,007
Unproved properties	3,151	114,202	9,567
Development costs (2)	583,488	528,686	780,851
Exploration costs: (3)			
Exploratory drilling	6,902	12,892	32,218
Geological and geophysical	64	253	3,017
Total costs incurred	$ 593,606	$ 2,274,033	$ 841,660

(1) Property acquisition costs represent costs incurred to purchase, lease or otherwise acquire a property.

(2) Development costs represent costs incurred to gain access to and prepare development well locations for drilling, drill and equip development wells, recomplete wells and provide facilities to extract, treat, gather and store crude oil, natural gas and NGLs. Of these costs incurred for the years ended December 31, 2021, 2020 and 2019, $227.8 million, $270.7 million and $308.9 million, respectively, were incurred to convert proved undeveloped reserves to proved developed reserves from the prior year end. These costs also include $35.3 million of infrastructure and pipeline costs in 2019. Our infrastructure and pipeline assets were divested in 2019.

(3) Exploration costs represent costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing crude oil, natural gas and NGLs. These costs include, but are not limited to, dry hole contributions and costs of drilling and equipping exploratory wells.

Capitalized Costs Related to Crude Oil and Natural Gas Producing Activities

Aggregate capitalized costs related to crude oil and natural gas exploration and production activities with applicable accumulated DD&A are presented below as of the dates indicated:

	December 31,	
	2021	2020
	(in thousands)	
Proved crude oil and natural gas properties	$ 8,310,018	$ 7,523,639
Unproved crude oil and natural gas properties	306,181	350,677
Uncompleted wells, equipment and facilities	371,360	523,376
Capitalized costs	8,987,559	8,397,692
Accumulated DD&A	(4,218,330)	(3,590,932)
Capitalized costs, net	$ 4,769,229	$ 4,806,760

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Reserves

The standardized measure below has been prepared in accordance with U.S. GAAP. Future estimated cash flows were based on a 12-month average price calculated as the unweighted arithmetic average of the prices on the first day of each month, January through December, applied to our year-end estimated proved reserves. Prices for each of the three years were adjusted by field for Btu content, transportation and regional price differences; however, they were not adjusted to reflect the value of our commodity derivatives. Production and development costs were based on prices as of December 31 for each of the respective years presented. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses, debt service or to depreciation, depletion and amortization expense. Production and development costs include those cash flows associated with the expected ultimate settlement of our asset retirement obligations. Future estimated income tax expense is computed by applying the statutory rate in effect at the end of each year to the projected future pre-tax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

The following table presents information with respect to the standardized measure of discounted future net cash flows relating to proved reserves as of the dates indicated. Changes in the demand for crude oil, natural gas and NGLs, inflation and other factors make such estimates inherently imprecise and subject to substantial revision. This table should not be construed to be an estimate of the current market value of our proved reserves.

	December 31,		
	2021	2020	2019
		(in thousands)	
Future estimated cash flows	$ 26,143,031	$ 12,481,830	$ 14,590,604
Future estimated production costs [1]	(6,325,129)	(4,209,459)	(4,530,173)
Future estimated development costs	(2,857,951)	(2,337,806)	(3,257,106)
Future estimated income tax expense	(3,088,187)	(301,507)	(907,382)
Future net cash flows	13,871,764	5,633,058	5,895,943
10% annual discount for estimated timing of cash flows	(5,963,592)	(2,350,879)	(2,585,609)
Standardized measure of discounted future estimated net cash flows	$ 7,908,172	$ 3,282,179	$ 3,310,334

(1) Represents future estimated lease operating expenses, production taxes and transportation, gathering and processing expenses.

The following table presents the principal sources of change in the standardized measure of discounted future estimated net cash flows for the periods presented:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Beginning of period	$ 3,282,179	$ 3,310,334	$ 4,447,716
Sales of crude oil, natural gas and NGLs production, net of production costs	(2,106,287)	(854,006)	(1,037,920)
Net changes in prices and production costs [1]	5,312,870	(1,771,019)	(2,122,538)
Extensions, discoveries and improved recovery, less related costs	20,201	14,110	39,606
Sales of reserves	—	(26,771)	(14,533)
Purchases of reserves	76,440	1,969,846	18,816
Development costs incurred during the period	338,098	329,495	605,753
Revisions of previous quantity estimates	2,645,379	(775,009)	538,242
Changes in estimated income taxes	(1,628,304)	354,369	346,826
Net changes in future development costs	(168,332)	367,630	206,003
Accretion of discount	345,454	572,483	532,127
Timing and other	(209,526)	(209,283)	(249,764)
End of period	$ 7,908,172	$ 3,282,179	$ 3,310,334

(1) Our weighted average price, net of production costs per Boe, in our 2021 reserve report increased to $24.34 as compared to $11.32 for 2020 and $16.18 for 2019.

The data presented should not be viewed as representing the expected cash flows from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the recent average prices and current costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

FINANCIAL STATEMENT SCHEDULE

Schedule II -VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance January 1,	Charged to Costs and Expenses	Deductions [1]	Ending Balance December 31,
			(in thousands)	
2021:				
Allowance for doubtful accounts	$ 6,763	$ (359)	$ (349)	$ 6,055
Allowance for expirations of unproved crude oil and natural gas properties	224,019	—	(17,691)	206,328
2020:				
Allowance for doubtful accounts	$ 7,476	$ 3,179	$ (3,892)	$ 6,763
Allowance for expirations of unproved crude oil and natural gas properties	6,881	223,895	(6,757)	224,019
2019:				
Allowance for doubtful accounts	$ 4,381	$ 3,209	$ (114)	$ 7,476
Allowance for expirations of unproved crude oil and natural gas properties	542,709	8,523	(544,351)	6,881

(1) For allowance for doubtful accounts, deductions represent the write-off of accounts receivable deemed uncollectible. For allowance for expirations of unproved crude oil and natural gas properties, deductions represent actual expired or abandoned unproved crude oil and natural gas properties, with a corresponding decrease to the historical cost of the associated asset.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2021, 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 December 31, 2021.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, and effected by our board of directors, management and other personnel 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

Management has assessed the effectiveness of our internal control over financial reporting as of December 31, 2021, based upon the criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this evaluation, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2021.

The effectiveness of our internal control over financial reporting as of December 31, 2021 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears under Item 8.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2022 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 11. EXECUTIVE COMPENSATION

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2022 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2022 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2022 Annual Stockholders' meeting and is incorporated by reference in this report.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information relating to this Item will be included in an amendment to this report or the proxy statement to be filed pursuant to Regulation 14A for our 2022 Annual Stockholders' meeting and is incorporated by reference in this report.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Exhibits:

See Exhibits Index on the following page.

ITEM 16. FORM 10-K SUMMARY

None.

Exhibits Index

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
2.1	Plan of Conversion, dated June 5, 2015, by PDC Energy, Inc.	8-K12B	001-37419	2.1	6/8/2015	
2.2	Agreement and Plan of Merger, dated as of August 25, 2019 by and between PDC Energy, Inc., and SRC Energy Inc.	8-K	001-37419	2.1	8/26/2019	
2.3	Membership Interest Purchase Agreement, dated as of February 26, 2022, by and among PDC Energy, Inc., Great Western Petroleum, LLC, and the members of Great Western Petroleum, LLC.	8-K	001-37419	2.1	2/28/2022	
3.1	Certificate of Incorporation of PDC Energy, Inc., as amended.	8-K12B	001-37419	3.1	5/27/2020	
3.2	Bylaws of PDC Energy, Inc.	8-K12B	001-37419	3.2	6/8/2015	
4.1	Description of Capital Stock					X

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
4.2	Form of Common Stock Certificate of PDC Energy, Inc.	10-K	001-37419	4.1.1	2/26/2020	
4.3	Base Indenture, dated as of September 14, 2016, by and between PDC Energy, Inc. and U.S. Bank Trust National Association, as Trustee.	8-K	001-37419	4.1	9/14/2016	
4.4	Indenture, dated as of September 15, 2016, by and between PDC Energy, Inc. and U.S. Bank Trust National Association, as Trustee, relating to the 6.125% Senior Notes due 2024.	8-K	001-37419	4.1	9/15/2016	
10.1	Form of Indemnification Agreement.	8-K	000-07246	10.1	6/8/2015	
10.2	Amended and Restated 2010 Long-Term Equity Compensation Plan, as amended.	10-K	001-37419	10.5	2/22/2016	
10.3	Executive Severance Compensation Plan, as amended and restated.	10-Q	001-37419	10.1	8/6/2020	
10.4	Form of 2013 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.10	2/27/2013	
10.5	Form of 2014 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.5	2/19/2015	
10.6	Form of 2015 Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.8	2/19/2015	
10.7	Form of 2019 Performance Share Agreement.	10-Q	001-37419	99.1	5/2/2019	
10.8	Form of 2019 Restricted Stock Unit Agreement (Executives) (Amended and Restated 2010 Long-Term Equity Compensation Plan).	10-Q	001-37419	99.3	5/2/2019	
10.9	Form of 2019 Restricted Stock Unit Agreement (Executives) (2018 Equity Incentive Plan).	10-Q	001-37419	99.4	5/2/2019	
10.10	SRC Energy, Inc./PDC Energy, Inc. Merger Performance Share Agreement, dated January 13, 2020, by and between PDC Energy, Inc.(as successor to SRC Energy, Inc.) and Lynn A. Peterson.	8-K	001-37419	10.2	1/14/2020	
10.11	Form of 2020 Performance Share Agreement.	10-Q	001-37419	99.1	5/7/2020	
10.12	Form of 2020 Restricted Stock Unit Agreement (Executives).	10-Q	001-37419	99.3	5/7/2020	
10.13	Form of 2021 Performance Share Agreement.	10-Q	001-37419	99.1	5/6/2021	
10.14	Form of 2021 Restricted Stock Unit Agreement (Directors).	10-Q	001-37419	99.2	5/6/2021	
10.15	Form of 2021 Restricted Stock Unit Agreement (Executives).	10-Q	001-37419	99.3	5/6/2021	
10.16	Employment Agreement with Lance A. Lauck, as amended.	10-Q	001-37419	10.2	8/6/2020	
10.17	2018 Equity Incentive Plan.	8-K	001-37419	10.1	5/31/2018	
10.18	Amendment No. 1 to PDC Energy, Inc. 2018 Equity Incentive Plan.	8-K	001-37419	10.1	5/27/2020	
10.19	SRC Energy Inc. 2015 Equity Incentive Plan.	8-K	001-37419	10.1	1/14/2020	
10.20	Fifth Amended and Restated Credit Agreement, dated as of November 2, 2021 among PDC Energy, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent and The Lenders Party Hereto	10-Q	001-37419	10.1	11/3/2021	
21.1	Subsidiaries.	10-K	001-37419	21.1	2/26/2020	
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of Ryder Scott Company, L.P., Petroleum Consultants.					X

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
23.3	Consent of Netherland, Sewell & Associates, Inc., Petroleum Consultants.					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.					
99.1	Report of Independent Petroleum Consultants - Ryder Scott Company, L.P.					X
99.2	Report of Independent Petroleum Consultants - Netherland, Sewell & Associates, Inc.					X
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 Section 13 or 15(d) 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.

By: /s/ Barton Brookman

Barton Brookman

President and Chief Executive Officer

February 28, 2022

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ Barton Brookman Barton Brookman	President, Chief Executive Officer and Director (principal executive officer)	February 28, 2022
/s/ R. Scott Meyers R. Scott Meyers	Senior Vice President and Chief Financial Officer (principal financial officer)	February 28, 2022
/s/ Douglas Griggs Douglas Griggs	Chief Accounting Officer (principal accounting officer)	February 28, 2022
/s/ Mark E. Ellis Mark E. Ellis	Non-Executive Chairman of the Board of Directors	February 28, 2022
/s/ Pamela R. Butcher Pamela R. Butcher	Director	February 28, 2022
/s/ Paul J. Korus Paul J. Korus	Director	February 28, 2022
/s/ David C. Parke David C. Parke	Director	February 28, 2022
/s/ Lynn A. Peterson Lynn A. Peterson	Director	February 28, 2022
/s/ Carlos A. Sabater Carlos A. Sabater	Director	February 28, 2022
/s/ Diana L. Sands Diana L. Sands	Director	February 28, 2022

GLOSSARY OF UNITS OF MEASUREMENT AND INDUSTRY TERMS

UNITS OF MEASUREMENT

The following presents a list of units of measurement used throughout the document.

Bbl – One barrel of crude oil or NGL or 42 gallons of liquid volume.
Bcf – One billion cubic feet of natural gas volume.
Boe – One barrel of crude oil equivalent.
Btu – British thermal unit.
BBtu – One billion British thermal units.
MBoe – One thousand barrels of crude oil equivalent.
MBbls – One thousand barrels of crude oil.
Mcf – One thousand cubic feet of natural gas volume.
MMBoe – One million barrels of crude oil equivalent.
MMBbls – One million barrels of crude oil.
MMBtu – One million British thermal units.
MMcf – One million cubic feet of natural gas volume.
MMcfd – One million cubic feet of natural gas volume per day.

GLOSSARY OF INDUSTRY TERMS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report:

Brent - Brent sweet light crude oil.

CIG - Colorado Interstate Gas.

Completion - Refers to the installation of permanent equipment for the production of crude oil and natural gas from a recently drilled well or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

Condensate - Liquid hydrocarbons associated with the production that is primarily natural gas.

Developed acreage - Acreage assignable to productive wells.

Development well - A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differentials - The difference between the crude oil and natural gas index spot price and the corresponding cash spot price in a specified location.

Dry well or dry hole - A well found to be incapable of producing hydrocarbons in sufficient quantities to justify completion as an oil or gas well.

Exploratory well - A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Extensions, discoveries and other additions - As to any period, the increases to proved reserves from all sources other than the acquisition of proved properties or revisions of previous estimates.

Fracture or *Fracturing* - Procedure to stimulate production by forcing a mixture of fluid and proppant into the formation under high pressure. Fracturing creates artificial fractures in the reservoir rock to increase permeability and porosity, thereby allowing the release of trapped hydrocarbons.

Gross acres or *wells* - Refers to the total acres or wells in which we have a working interest.

Henry Hub - Refers to the pricing point for natural gas futures contracts traded on NYMEX.

Horizontal drilling - A drilling technique that permits the operator to drill a horizontal well shaft from the bottom of a vertical well and thereby to contact and intersect a larger portion of the producing horizon than conventional vertical drilling techniques and may, depending on the horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

Intensity - Greenhouse gas and methane intensity is reported as total metric tons of methane emissions divided by gross annual production in MBOE.

Joint interest billing - Process of billing/invoicing the costs related to well drilling, completions and production operations among working interest partners.

Natural gas liquid(s) or *NGL(s)* - Hydrocarbons which can be extracted from natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs include ethane, propane, butane and other natural gasolines.

Net acres or *wells* - Refers to gross acres or wells we own multiplied, in each case, by our percentage working interest.

Net production - Crude oil and natural gas production that we own, less royalties and production due to others.

Non-operated - A project in which we are not the operator.

NYMEX - New York Mercantile Exchange.

Operator - The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

Overriding royalty - An interest which is created out of the operating or working interest. Its term is coextensive with that of the operating interest.

Possible reserves - This term is defined in the SEC Regulation S-X Section 4-10(a) and refers to those reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability to exceed the sum of proved, probable and possible reserves. When probabilistic methods are used, there must be at least a 10 percent probability that the actual quantities recovered will equal or exceed the sum of proved, probable and possible estimates.

Present value of future net revenues or *(PV-10)* - The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, of proved reserves calculated in accordance with Financial Accounting Standards Board guidelines, net of estimated production and future development costs, using pricing and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization and discounted using an annual discount rate of 10 percent. PV-10 is pre-tax and therefore a non-U.S. GAAP financial measure.

Probable reserves - This term is defined in the SEC Regulation S-X Section 4-10(a) and refers to those reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. Similarly, when probabilistic methods are used, there must be at least a 50 percent probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

Productive well - An exploratory or developmental well that is not a dry well or dry hole, as defined above.

Proved developed non-producing reserves - Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and/or (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed producing reserves or *PDPs* - Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

Proved developed reserves - The combination of proved developed producing and proved developed non-producing reserves.

Proved reserves - This term means “proved oil and gas reserves” as defined in SEC Regulation S-X Section 4-10(a) and refers to those quantities of crude oil and condensate, natural gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, and under existing conditions, operating methods and government regulations - prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved undeveloped reserves or *PUDs* - Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Recomplete or *Recompletion* - The modification of an existing well for the purpose of producing crude oil and natural gas from a different producing formation.

Reserves - Estimated remaining quantities of crude oil, natural gas, NGLs and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering crude oil, natural gas and NGLs or related substances to market, and all permits and financing required to implement the project.

Royalty - An interest in a crude oil and natural gas lease or mineral interest that gives the owner of the royalty the right to receive a portion of the production from the leased acreage or mineral interest (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner’s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Spud - To begin drilling; the act of beginning a hole.

Standardized measure of discounted future net cash flows or *standardized measure* - Future net cash flows discounted at a rate of 10 percent. Future net cash flows represent the estimated future revenues to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, giving effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment and (ii) future income tax expense.

Stratigraphic test well - A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production.

Undeveloped acreage - Leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas, regardless of whether such acreage contains proved reserves.

Waha - Waha West Texas natural gas prices

Working interest - An interest in a crude oil and natural gas lease that gives the owner of the interest the right to drill and produce crude oil and natural gas on the leased acreage. It requires the owner to pay its share of the costs of drilling and production operations.

Workover - Major remedial operations on a producing well to restore, maintain, or improve the well’s production.

Exhibit 4.1

DESCRIPTION OF THE REGISTRANT’S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following is a summary of the common stock, $0.01 par value per share (the “common stock”), of PDC Energy, Inc. (the “Company”), which is the only class of the Company’s securities registered under Section 12 of the Securities Exchange Act of 1934, as amended. The following summary is not complete. You should refer to the applicable provisions of the Company’s certificate of incorporation, the Company’s bylaws, and the General Corporation Law of the State of Delaware (“DGCL”), including Section 203, for a complete statement of the terms and rights of the common stock. Copies of the certificate of incorporation and bylaws have been filed with the Securities and Exchange Commission as Exhibits 3.1 and 3.2, respectively, to the Company’s Annual Report on Form 10-K.

Common Stock

The Company’s certificate of incorporation authorizes the issuance of 150,000,000 shares of common stock. Holders of common stock of the Company are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders and do not have cumulative voting rights. Except as may be otherwise provided in a preferred stock designation, holders of common stock have the exclusive right to vote for the election of directors.

Subject to prior rights and preferences that may be applicable to any outstanding shares or series of preferred stock, holders of common stock are entitled to receive ratably in proportion to the shares of common stock held by them such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by the Company’s board of directors out of funds legally available for dividend payments. All outstanding shares of common stock are fully paid and non-assessable. The holders of common stock have no preferences or rights of conversion, exchange or pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to the common stock. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of the Company’s affairs, holders of common stock will be entitled to share ratably in the Company’s assets in proportion to the shares of common stock held by them that are remaining after payment or provision for payment of all of the Company’s debts and obligations and after distribution in full of preferential amounts to be distributed to holders of outstanding shares of preferred stock, if any.

Anti-takeover Effects of Delaware Law and Provisions of the Company’s Certificate of Incorporation and Bylaws

Delaware Law

Section 203 of the Delaware General Corporation Law (the “DGCL”) generally prohibits a Delaware corporation from engaging in any “business combination” with any “interested stockholder” for a period of three years following the date that the stockholder became an interested stockholder, unless:

- prior to such time, either the business combination or the transaction in which the stockholder became an interested stockholder was approved by the board of directors;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced; or

- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

An “interested stockholder” is generally defined as a person or group that beneficially owns 15% or more of the corporation’s outstanding common stock. A “business combination” includes a merger, consolidation, sale of assets or other transaction resulting in a financial benefit to the stockholder.

Certificate of Incorporation and Bylaws

The certificate of incorporation and bylaws:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of the Company’s stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to the corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at the Company’s principal executive office not less than 80 days nor more than 90 days prior to the first anniversary date of the annual meeting for the preceding year. The bylaws specify the requirements as to form and content of all stockholders’ notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting; and

- provide that the authorized number of directors may be changed only by resolution of the board of directors and may not exceed a total of nine.

Limitation of Liability and Indemnification Matters

The certificate of incorporation limits the liability of the Company's directors for monetary damages for breach of their fiduciary duty as directors, except for liability that cannot be eliminated under the DGCL.

Any amendment, repeal or modification of these provisions will be prospective only and would not affect any limitation on liability of a director for acts or omissions that occurred prior to any such amendment, repeal or modification.

The bylaws also provide that the Company will indemnify its directors and officers to the fullest extent permitted by Delaware law. The Company has entered into indemnification agreements with each of its directors pursuant to which it has generally agreed to provide indemnification and advancement to the directors to the maximum extent permitted by the DGCL.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-256308 and No. 333-215422) and Form S-8 (No. 333-239433, No. 333-189685, No. 333-167945, No. 333-118215, No. 333-225596 and No. 333-235908) of PDC Energy, Inc. of our report dated February 28, 2022, relating to the financial statements, financial statement schedule, and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Denver, Colorado
February 28, 2022

Exhibit 23.2

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

Consent of Independent Petroleum Engineers

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 of PDC Energy, Inc. (333-256308 and 333-215422) and to the incorporation by reference in the Registration Statements on Form S-8 of PDC Energy, Inc. (No. 333-189685, No. 333-167945, No. 333-118215, No. 333-225596, No. 333-235908, and No. 333-239433), of all references to our firm and information from our reserves report dated January 17, 2022, included in or made a part of PDC Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2021, and our summary report attached as Exhibit 99.1 to the Annual Report on Form 10-K.

/s/ Ryder Scott Company, L.P.
RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Denver, CO
February 28, 2022

Exhibit 23.3

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 of PDC Energy, Inc. (No. 333-256308 and No. 333-215422) and to the incorporation by reference in the Registration Statements on Form S-8 of PDC Energy, Inc. (No. 333-189685, No. 333-167945, No. 333-118215, No. 333-225596, No. 333-235908, and No. 333-239433), of all references to our firm and information from our reserves report dated January 20, 2022, included in or made a part of PDC Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2021, and our summary report attached as Exhibit 99.2 to the Annual Report on Form 10-K.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 28, 2022

Exhibit 31.1

CERTIFICATIONS

I, Barton Brookman, certify that:

1. I have reviewed this Annual Report on Form 10-K 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: February 28, 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 Annual Report on Form 10-K 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: February 28, 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 Annual Report of PDC Energy, Inc. (the "Company") on Form 10-K for the period ended December 31, 2021, 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	February 28, 2022
Barton Brookman President and Chief Executive Officer (principal executive officer)	
/s/ R. Scott Meyers	February 28, 2022
R. Scott Meyers Senior Vice President and Chief Financial Officer (principal financial officer)	

PDC Energy, Inc.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2021

/s/ Stephen G. Gardner	/s/ Edward M. Polishuk
Stephen E. Gardner, P.E.	Edward M. Polishuk
Colorado License No. 44720	Senior Petroleum Evaluator
Managing Senior Vice President	

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 17, 2022

PDC Energy, Inc.
1775 Sherman Street
Denver, Colorado 80203

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of PDC Energy, Inc. (PDC) as of December 31, 2021. The subject properties are located in the state of Colorado. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 17, 2022 and presented herein, was prepared for public disclosure by PDC in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott account for a portion of PDC's total net proved reserves as of December 31, 2021. Based on information provided by PDC, the third party estimate conducted by Ryder Scott addresses 84 percent of the total proved developed net liquid hydrocarbon reserves, 87 percent of the total proved developed net gas reserves, 95 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 96 percent of the total proved undeveloped net gas reserves of PDC.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2021 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

1100 LOUISIANA, SUITE 4600 HOUSTON, TEXAS 7702-5294 TEL (713) 651-9191 FAX (713) 651-0849
SUITE 2800, 350 7TH AVE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
PDC Energy, Inc.
As of December 31, 2021

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate - Mbbl	73,320	3,286	108,924	185,530
Plant Products - Mbbl	102,700	3,592	116,058	222,350
Gas - MMcf	916,734	29,176	1,026,443	1,972,353
Income Data ($M)				
Future Gross Revenue	$ 9,623,173	$ 380,590	$ 12,675,871	$ 22,679,634
Deductions	2,433,877	219,291	4,659,315	7,312,483
Future Net Income (FNI)	$ 7,189,296	$ 161,299	$ 8,016,556	$ 15,367,151
Discounted FNI @ 10%	$ 4,677,788	$ 105,580	$ 3,955,919	$ 8,739,287

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIESTM Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of PDC. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 76 percent and gas reserves account for the remaining 24 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates, which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income - ($M) As of December 31, 2021 Total Proved
5	$ 11,211,862
15	$ 7,130,089
20	$ 6,011,310
25	$ 5,194,232

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non- producing reserves included herein consist of shut-in wells waiting for abandonment, low volume wells waiting for optimal pipeline pressure, and completed horizontal wells waiting for facility construction.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At PDC's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

PDC's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which PDC owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods, which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods or analogy. All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include decline curve analysis, which utilized extrapolations of historical production and pressure data available through December 2021 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by PDC or obtained from public data sources and were considered sufficient for the purpose thereof.

Approximately 15 percent of the proved developed non-producing reserves included herein were estimated by performance methods, in particular, decline curve analysis prior to the wells being shut in. The remaining 85 percent of proved developed non-producing reserves and all of the proved undeveloped reserves included herein were estimated by analogy. The data utilized from the shut-in wells and from the analogues were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

PDC has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by PDC with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by PDC. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by PDC. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

PDC furnished us with the above mentioned average prices in effect on December 31, 2021. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the- month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by PDC. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by PDC to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$66.56/bbl	$65.65/bbl
	NGLs	WTI Cushing	$66.56/bbl	$24.11/bbl
	Gas	Henry Hub	$3.598/MMBTU	$2.82/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by PDC and are based on the operating expense reports of PDC and include only those costs directly applicable to the leases and wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by PDC**.** No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases and wells.

Development costs were furnished to us by PDC and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by PDC were accepted without independent verification.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with PDC's plans to develop these reserves as of December 31, 2021. The implementation of PDC's development plans as presented to us and incorporated herein is subject to the approval process adopted by PDC's management. As the result of our inquiries during the course of preparing this report, PDC has informed us that the development activities included herein have been subjected to and received the internal approvals required by PDC's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to PDC. PDC has provided written documentation supporting their commitment to proceed with the development activities as presented to us**.** Additionally, PDC has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2021 such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by PDC were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to PDC. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by PDC.

PDC makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, PDC has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-8 of PDC, of the references to our name, as well as to the references to our third party report for PDC, which appears in the December 31, 2021 annual report on Form 10-K of PDC. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by PDC.

We have provided PDC with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by PDC and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.
TBPE Firm Registration No. F-

/s/

Stephen G. Gardner

Stephen

E. Gardner, P.E.

Colorado

License No. 44720

Managing

Senior Vice President

/s/

Edward M. Polishuk

Edward

M. Polishuk

Senior

Petroleum Evaluator

SEG-EMP (LPC)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

January 20, 2022

Mr. Erik Roach
PDC Energy, Inc.
1775 Sherman Street, Suite 3000
Denver, Colorado 80203

Dear Mr. Roach:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2021, to the PDC Energy, Inc. (PDC) interest in certain oil and gas properties located in Culberson and Reeves Counties, Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 10 percent of all proved reserves owned by PDC. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for PDC's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the PDC interest in these properties, as of December 31, 2021, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	20,813.2	13,840.2	142,790.3	1,202,642.0	740,120.8
Proved Developed Non-Producing[1]	0.0	0.0	0.0	-3,149.1	-2,945.7
Proved Undeveloped	7,501.4	4,198.4	44,581.2	393,316.5	232,390.6
Total Proved	28,314.7	18,038.7	187,371.5	1,592,809.5	969,565.8

Totals may not add because of rounding.

[1] There are no proved developed non-producing reserves at the price and cost parameters used in this report. Future net revenue is negative after deducting estimated abandonment costs and operating expenses.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. No study was made to determine whether probable or possible reserves might be established for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is PDC's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for PDC's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2021. For oil and NGL volumes, the average West Texas Intermediate spot price of $66.561 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $3.598 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $63.52 per barrel of oil, $35.36 per barrel of NGL, and $3.271 per MCF of gas.

Operating costs used in this report are based on operating expense records of PDC. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Headquarters general and administrative overhead expenses of PDC are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by PDC and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are PDC's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the PDC interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on PDC receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by PDC, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from PDC, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Neil H. Little, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2011 and has over 9 years of prior industry experience. Edward C. Roy III, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered engineering firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Neil H. Little
Neil H. Little, P.E. 117966
Vice President

Date signed: January 20, 2022

By: /s/ Edward C. Roy III
Edward C. Roy III, P.G. 2364
Vice President

Date signed: January 20, 2022

NHL: SMD

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:
932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.