PrimeEnergy

PrimeEnergy Resources Corporation

ANNUAL REPORT
2022

Chairman's Letter

Dear Shareholder,

2022 will be remembered as a transformational year in the history of PrimeEnergy Resources Corporation….a year when we achieved record profits of over forty-eight million dollars ($48,000,000) and free cashflow over seventy-six million dollars ($76,000,000), made a series of strategic investments, all while reducing our RBL (Reserve Base Loan) to zero. Armed with a very strong balance sheet and zero debt, we are well positioned during the next fiscal year to take advantage of market opportunities.

From a strategic perspective, we were steadfast in our plan to strengthen our balance sheet, diversify our drilling opportunities and broaden our footprint. Key to the execution of the strategy has been our ability to partner with some of the industry's most respected companies including APACHE, CONOCOPHILLIPS, DOUBLE EAGLE, and HIBERNIA RESOURCES. These and many other companies seek us out despite our relative size; they do so because of our outstanding acreage position in the Permian basin.

In 2013 with our bank loan at one hundred twenty-two million dollars ($122,000,000) we made a corporate decision to attempt to reduce our indebtedness, but to continue to increase our reserves and return money to our shareholders through our share buyback program….MISSION ACCOMPLISHED!

In 2022, the Company participated with SEM Operating Company, LLC in four horizontal wells in Irion County, Texas with 10.3% interest for approximately two-million, three hundred, fifty thousand dollars ($2,350,000) and with Ovintiv Mid-Continent, Inc. in four horizontal wells in Canadian County, Oklahoma with an average of 9% interest for one million, seven hundred, seventy-seven thousand dollars ($1,770,000). All eight wells were put into production in August of 2022.

In the fourth quarter of 2022, we began participation in the drilling of 20 horizontal wells located in West Texas operated by three different operators. In Martin County, we are participating with ConocoPhillips in five 2.5-mile-long horizontal wells in which the Company has 20.83% interest with a planned capital expense of twelve million, one hundred thousand dollars ($12,100,000). In Reagan County we are participating with Hibernia Energy III in 10 two-mile horizontals with 25% interest and an expected investment of twenty-five million, six hundred thousand dollars ($25,600,000). Also in Reagan County, we are participating with Double Eagle (DE IV) in five two-mile-long horizontals with nearly 50% interest, carrying an expected net capital outlay of twenty-three million, four hundred thousand dollars ($23,400,000). All twenty of these West Texas wells are currently drilling or have been completed. All are expected to be on line in the second quarter of 2023.

In January of 2023, the Company joined Ovintiv USA, Inc. in the spudding of three 3-mile-long horizontal wells in Canadian County, Oklahoma with 1.96% interest and an expected investment of $645,000. Production is expected to begin in May 2023. In addition, in March of 2023, Apache Corporation has spud two 3-mile-long horizontals in Upton County, Texas in which the Company has 49.4% interest with an expected total capital investment of sixteen million, one hundred thousand dollars ($16,100,000). We anticipate completion of these two 15,000' long horizontals in Upton County in May and production to occur in June of 2023.

In total, the Company expects to invest seventy-eight million dollars ($78,000,000) in these 25 horizontal wells. We prepaid drilling cost of thirty-two million dollars ($32,000,000) in December of 2022 drawing down on our RBL facility and the remaining forty-six million dollars ($46,000,000) estimated drilling and completion expense will occur in 2023. All 25 wells are expected to be completed and on-line in the second quarter of 2023.

We anticipate that success from the 22 horizontals in West Texas described above will lead to additional near-term horizontal drilling covering five leasehold blocks in three counties of West Texas: 29 additional

10,000’ long horizontals in Reagan County from Hibernia, Double Eagle, and BTA Oil Producers (or its successor in the South Stiles Project), ten additional 12,500’ long horizontals in Martin County by ConocoPhillips, and six additional 15,000’ long horizontals in Upton County by Apache. These anticipated additional 42 drilling proposals will target various proven pay intervals of the Wolfcamp and Spraberry formations and will require an estimated $200 million in net capital investment. In addition, we have more than 200 drilling locations that could potentially be developed.

During 2021 we essentially paused our share repurchase program because of the company’s financial position and only repurchased two thousand one hundred (2,100) shares. In 2022, we re-accelerated our share repurchase program and retired ninety-one thousand seventy-seven (91,077) shares which were placed into treasury. This represents 3% of the shares outstanding on a fully diluted basis. In 2023, we will continue our share repurchase program.

Throughout the course of these last 33 years, our share repurchase program has returned in excess of $88,000,000 to our shareholders. Why this accomplishment is so impressive is the company had a mere market value of $9,000,000 in 1990.

Also, in 1990 there were approximately 7,600,000 shares outstanding today there are 1,866,500 shares outstanding. We have now retired approximately seventy-five percent (75%) of the outstanding shares of the company. In 1991 we also retired 769,500 options which today would represent 29% of the fully diluted outstanding shares of the company. The cost to retire those options was $607,000.

The annual Meeting of Shareholders will be held at our office at 9821 Katy Freeway, Suite 1050 Houston, Texas on June 7, 2023, at 9:00 am (CDT). I encourage you to attend and meet our Board of Directors and management team and allow us to answer any questions you may have.

PrimeEnergy Resources Corporation

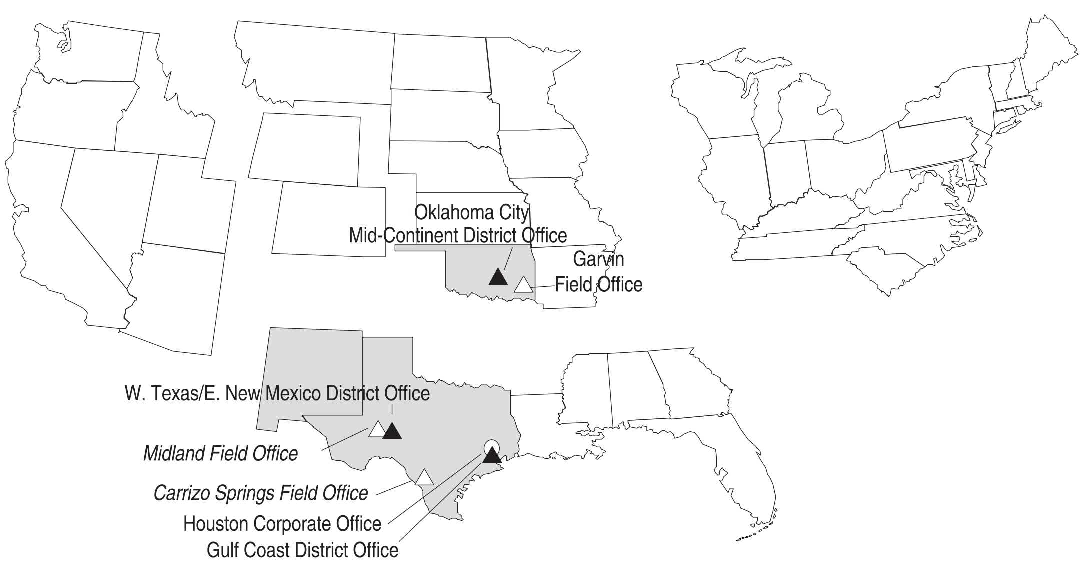
Charles E. Drimal, Jr.
Chairman and Chief Executive Officer

The Company

PrimeEnergy Resources Corporation ("the Company") is an independent oil and gas company actively engaged in acquiring, developing and producing oil and natural gas. The Company's common stock shares are traded in the NASDAQ stock market under the symbol "PNRG."

The Company is headquartered in Houston, Texas, with operating offices in Midland, Texas, and Oklahoma City, Oklahoma. PrimeEnergy owns leasehold, mineral and royalty interests in producing and non-producing oil and gas properties across the continental United States. The Company operates approximately 630 active wells and owns non-operating and royalty interests in over 800 additional wells.

Operations are conducted through the Company's principal offices in Houston, Texas, and district offices in Oklahoma City, Oklahoma, and Midland, Texas. With field offices in Oklahoma and Texas. Through its equipment companies, the Company provides well service support operations, site preparation and construction services for drilling and re-working operations, both in connection with the Company's activities and providing contract services for third parties.



The Company's Annual Report, Form 10-K for the year ended December 31, 2022, as filed with the Securities and Exchange Commission is reproduced herein (except for exhibits) as the Company's Annual Report for 2022 to its shareholders. The Form 10-K includes the Company's audited financial statements and other financial data and information, a description of the Company's business and properties and other pertinent information concerning the Company.

Corporate Information

Auditors

Grassi & Co., CPAs, P.C.
New York, New York

Commercial Bankers

Citibank, N.A.

Fifth Third Bank

West Texas National Bank

Transfer Agent

Computershare Trust Company, N.A.
P.O. Box 30170
College Station, Texas 77842-3170

Annual Meeting

June 7, 2023 at 9:00 a.m. CDT
at the offices of the Company
9821 Katy Freeway
Houston, Texas 77024

NASDAQ Symbol
PNRG

Executive Offices

9821 Katy Freeway
Houston, Texas 77024

Operating Offices

Prime Operating Company
Houston, Texas
Midland, Texas
Oklahoma City, Oklahoma
Field Offices:
Garvin, Oklahoma
Carrizo Springs, Texas
Midland, Texas

PrimeEnergy Management Corporation
Houston, Texas

Eastern Oil Well Service Company
Midland, Texas
Carrizo Springs, Texas

10-K Information

The Company's 2022 Annual Report on Form 10-K, as filed with the Securities and Exchange Commission (except for exhibits) is included herein. Exhibits to the Form 10-K, which are indexed therein, are available upon request and the payment of a reproduction charge of fifteen cents per page by writing to:

PrimeEnergy Resources Corporation
9821 Katy Freeway
Houston, Texas 77024
Attn: Investor Relations

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2022

Or

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

For the Transition Period From ________ to________.

is Commission File Number 0-7406

PrimeEnergy Resources Corporation
(Exact name of registrant as specified in its charter)

Delaware	**84-0637348**
(state or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
9821 Katy Freeway, Houston, Texas	**77024**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (713) 735-0000

Securities registered pursuant to Section 12(g) of the Act

Title of each class	Trading Symbol	Name of each Exchange on which registered
Common Stock, par value $0.10 (per share)	PNRG	NASDAQ

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ 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 ☒

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the 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 is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Auditor PCAOB ID Number: 606 **Auditor Name: Grassi & Co., CPAs, P.C.** **Auditor Location: New York, NY**

The aggregate market value of the voting stock of the Registrant held by non-affiliates, computed by reference to the average bid and asked price of such common equity as of the last business day of the Registrant's most recently completed second fiscal quarter, was $59,992,464.

The number of shares outstanding of each class of the Registrant's Common Stock as of April 10, 2023 was 1,867,500 Common Stock, $0.10 par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's proxy statement to be furnished to stockholders in connection with its Annual Meeting of Stockholders to be held on June 7, 2023, are incorporated by reference in Part III hereof.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Report") contains forward-looking statements that involve risks and uncertainties. When used in this document, the words "believes," "plans," "expects," "anticipates," "forecasts," "models," "intends," "continue," "may," "will," "could," "should," "future," "potential," "estimate," or the negative of such terms and similar expressions as they relate to the Company are intended to identify forward-looking statements, which are generally not historical in nature. The forward-looking statements are based on the Company's current expectations, assumptions, estimates and projections about the Company and the industry in which the Company operates. Although the Company believes that the expectations and assumptions reflected in the forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. In addition, the Company may be subject to currently unforeseen risks that may have a materially adverse effect on it. These risks and uncertainties include, among other things, volatility of commodity prices; product supply and demand; the impact of armed conflict (including the war in Ukraine) and political instability on economic activity and oil and gas supply and demand; competition; the ability to obtain drilling, environmental and other permits and the timing thereof; the effect of future regulatory or legislative actions on the Company or the industry in which it operates, including potential changes to tax laws; the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms; potential liability resulting from pending or future litigation; the costs, including the potential impact of cost increases due to inflation and supply chain disruptions, and results of development and operating activities; the impact of a widespread outbreak of an illness, such as the COVID-19 pandemic, on global and U.S. economic activity, oil and gas demand, and global and U.S. supply chains; the risk of new restrictions with respect to development activities, including potential changes to regulations resulting in limitations on the Company's ability to dispose of produced water; availability of equipment, services, resources and personnel required to perform the Company's development and operating activities; access to and availability of transportation, processing, fractionation, refining, storage and export facilities; the Company's ability to replace reserves, implement its business plans or complete its development activities as scheduled; access to and cost of capital; the financial strength of counterparties to the Company's credit facility, derivative contracts, and purchasers of the Company's oil, NGL and gas production; uncertainties about estimates of reserves, identification of drilling locations and the ability to add proved reserves in the future; the assumptions underlying forecasts, including forecasts of production, operating cash flow, well costs, capital expenditures, rates of return, expenses; tax rates; quality of technical data; environmental and weather risks, including the possible impacts of climate change on the Company's operations and demand for its products; cybersecurity risks; the risks associated with the ownership and operation of the Company's well services business and acts of war or terrorism. In addition, the Company may be subject to currently unforeseen risks that may have a materially adverse effect on it. Accordingly, no assurances can be given that the actual events and results will not be materially different than the anticipated results described in the forward-looking statements. See Items 1 and 2—Business and Properties—Estimated Proved Reserves and Future Net Cash Flows, Item 1A—Risk Factors, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations, and elsewhere in this Form 10-K for descriptions of various factors that could materially affect the ability of the Company to achieve the anticipated results described in the forward-looking statements. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, we assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

PrimeEnergy Resources Corporation

FORM 10-K ANNUAL REPORT
For the Fiscal Year Ended
December 31, 2022

PART I

Item 1. BUSINESS.

General

PrimeEnergy Resources Corporation (the "Company") was organized in March 1973, under the laws of the State of Delaware. We are an independent oil and natural gas company engaged in acquiring, developing, and producing oil and natural gas. We presently own producing and non-producing properties located primarily in Texas, and Oklahoma. All of our oil and gas properties and interests are located in the United States. Through our subsidiaries Prime Operating Company, Eastern Oil Well Service Company, and EOWS Midland Company, we act as operator and provide well-servicing support operations for many of the onshore oil and gas wells we operate, as well as for third parties. We are also active in the acquisition of producing oil and gas properties through joint ventures with industry partners. In addition, we own a 12.5% overriding royalty interest in over 30,000 acres in the state of West Virginia. We are currently not receiving revenue from this asset, as development has not begun. In addition, through a wholly owned offshore company, we own a 60-mile-long pipeline offshore on the shallow shelf of Texas, not currently in use. We also hold a 33.3% interest in a limited partnership that owns a 138,000-square-foot retail shopping center on ten acres in Prattville, Alabama, which is on our books for $40 thousand. There is currently no debt on the shopping center and it has approximately $500,000 of working capital on its balance sheet.

Additional Information

PrimeEnergy files or furnishes annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934 (the "Exchange Act"). The SEC maintains a website (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, including PrimeEnergy, that file electronically with the SEC.

The Company makes available, free of charge, through its website (www.primeenergy.com) its Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC. In addition to the reports filed or furnished with the SEC, Pioneer publicly discloses information from time to time in its press releases. Such information, including information posted on or connected to the Company's website, is not a part of, or incorporated by reference in, this Report or any other document the Company files with or furnishes to the SEC.

Exploration, Development, and Recent Activities

The Company's activities include development and exploratory drilling. Our strategy is to develop the Company's extensive oil and gas reserves primarily through horizontal drilling. This strategy includes targeting reservoirs with high initial production rates and cash flow as well as targeting reservoirs with lower initial production rates but with higher expected return on investment. We believe that with today's technology, horizontal development of our reserves provides superior economic results as compared to vertical development, by delivering higher production rates through greater contact and stimulation of a larger volume of reservoir rock while minimizing the surface footprint required to develop those same reserves.

Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. In 2023, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our capital budget for the year is reflective of current commodity prices and has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility. As we have done historically to preserve or enhance liquidity, we may adjust our capital program throughout the year, divest non-strategic assets, or enter into strategic joint ventures.

We are actively developing our leasehold acreage in West Texas and in Oklahoma and on track to drill and complete approximately 40 wells in 2023. The following is a description of recent, current, and expected near-term drilling activities.

In 2021, The Company participated for 47.5% interest with Apache Corporation in the drilling of nine two-mile-long horizontal wells in Upton County, Texas, and with Ovintiv Mid-Continent for 11.25% interest in four two-mile horizontal wells in Canadian County, Oklahoma. Twelve of these horizontal wells were completed and placed into production in the fourth quarter of 2021. One of the Ovintiv wells, however, had a casing leak issue and has been temporarily abandoned. The Company invested approximately $32 million in these thirteen wells.

In the first three quarters of 2022, the Company participated in eight horizontal wells. Four of these wells are located in Irion County, West Texas, operated by SEM Operating Company, and four are located in Canadian County, Oklahoma, operated by Ovintiv Mid-Continent, Inc. Our investment in these eight wells was approximately $4 million and all were brought on production in August of 2022.

In the fourth quarter of 2022, we began participation in the drilling of 20 horizontal wells located in West Texas operated by three different operators. In Martin County, we are participating with ConocoPhillips in five 2.5-mile-long horizontal wells in which the Company has 20.83% interest with a planned capital investment of $12.1 million. In Reagan County, we are participating with Hibernia Energy III in 10 two-mile horizontals with 25% interest and an expected investment of $25.6 million. Also in Reagan County, we are participating with Double Eagle (DE IV) in five two-mile-long horizontals with nearly 50% interest, carrying an expected net capital outlay of $23.4 million. All twenty of these West Texas wells are currently drilling or have been completed. All are expected to be on line in the second quarter of 2023.

January of 2023, the Company joined Ovintiv USA, Inc. in the spudding of three 3-mile-long horizontal wells in Canadian County, Oklahoma with 1.96% interest and an expected investment of $645,000. Production is expected to begin in May 2023. In addition, in March of 2023, Apache Corporation spud two 3-mile-long horizontals in Upton County, Texas in which the Company has 49.4% interest with an expected total capital investment of $16.1 million. We anticipate completion of these two 15,000’ long horizontals in Upton County in May and production to occur in June of 2023.

In total, the Company expects to invest $78 million in these 25 horizontal wells. In December 2022, we prepaid $32 million toward drilling costs, and the remaining $46 million in estimated drilling and completion expenses will be incurred in 2023. All 25 wells are expected to be completed and on-line in the second quarter of 2023.

We anticipate that success from the 22 horizontals in West Texas described above will lead to additional near-term horizontal drilling covering five leasehold blocks in three counties of West Texas: 26 additional 10,000’ long horizontals in Reagan County from Hibernia, Double Eagle, and BTA Oil Producers (or its successor in the South Stiles Project), ten additional 12,500’ long horizontals in Martin County by ConocoPhillips, and six additional 15,000’ long horizontals in Upton County by Apache. These anticipated additional 42 drilling proposals will target various proven pay intervals of the Wolfcamp and Spraberry formations and will require an estimated $200 million in net capital investment through 2024. We have also identified 27 horizontal locations that would be a natural progression of development for three of these project areas in Upton and Reagan counties. These 27 wells are anticipated to be drilled in the 2025-2026 timeframe and would require net investment of approximately $100 million. In total, with the $78 million current investment in 22 wells, the $200 million near-term investment in 42 wells, and the $100 million in 27 subsequent drill sites, we are planning for an investment of approximately $400 million in horizontal development over the next several years.

In the Permian Basin of West Texas and eastern New Mexico we maintain an acreage position of approximately 16,940 gross (9,969 net) acres, 96.5% of which is located in Reagan, Upton, Martin, and Midland counties of Texas where our current West Texas horizontal drilling activities are focused. We believe this acreage has the resource potential to support the drilling of as many as 190 future horizontal wells following the active 22 and anticipated 42 horizontal wells described above.

In Oklahoma, we are focused on the development of our reserves in Canadian, Grady, Kingfisher, Garfield, Major, and Garvin counties where we have approximately 4,113 net leasehold acres in the Scoop/Stack Play. Of this acreage, we believe 2,355 net leasehold acres hold significant additional resource potential that could support the drilling of as many as 46 new horizontal wells based on an estimate of four wells per multi-section drilling unit, two in the Mississippian and two in the Woodford Shale. In the near term, we anticipate nine new drilling proposals to be received with an estimated net expense of $5.2 million covering 338 net leasehold acres. Proposals may be received on the remaining 2,017 acres, however, rather than participate we may choose to sell the acreage or farm-out, receiving cash and retaining an over-riding royalty interest.

Significant Activity

As of December 31, 2022, we had net capitalized costs related to proved oil and gas properties of $169.5 million. Total expenditures for the acquisition, exploration, and development of our properties during 2022 were $14.0 million as we continue development under the programs discussed above. Proved reserves as of December 31, 2022, were 16,718 MBOE which consisted of 62% proved developed reserves and 38% proved undeveloped reserves.

During the first three quarters of 2022, the Company participated in the drilling and completion of eight completed horizontal wells put into production in August 2022. The Company participated with a 9% interest in four horizontals located in Canadian County, Oklahoma, operated by Ovintiv Mid-Continent, Inc., and with a 10.13% interest in four wells located in Irion County, Texas, operated by SEM Operating Company. The Company is actively participating in 25 horizontals, 22 of which are in the West Texas Spraberry and Wolfcamp trend and three of which are in the Oklahoma Scoop Stack play. In total, the Company will invest approximately $78 million in these 25 horizontals that are expected to be in production in the second quarter of 2023. Additional development on these same leasehold blocks and adjacent Company owned blocks is anticipated in the second half of 2023 and 2024.

In 2022, the Company entered into an agreement with Double Eagle to create a 2,560-acre AMI for the joint development of horizontal wells; as part of this agreement, the Company sold a portion of its interest in this acreage for proceeds of $16.1 million. In addition, in 2022, we sold 240 net acres in Reagan County to BTA Oil Producers for proceeds of $1.8 million, and we sold 353 net acres in Canadian County, Oklahoma to Paloma Partners, IV, Inc. for $1.3 million. Through three other transactions, we divested a minor tract in Lea County, NM for a nominal cash consideration and assigned nine wellbores in West Texas to a third-party operator in exchange for a reduction in our future plugging liability. In this same year, the Company acquired 3.2 net mineral acres in Upton County, Texas for $16,000.

We believe that our diversified portfolio approach to our drilling activities produces more consistent and predictable economic results than would otherwise be experienced with a less diversified or higher-risk drilling program profile.

We attempt to assume the position of operator in all acquisitions of producing properties. We will continue to evaluate prospects for leasehold acquisitions and for exploration and development operations in areas in which we own interests and are actively pursuing the acquisition of producing properties. To diversify and broaden our asset base, we will consider acquiring the assets or stock in other entities and companies in the oil and gas business. Our main objective in making any such acquisitions will be to acquire income-producing assets to increase our net worth and increase our oil and gas reserve base.

We presently own producing and non-producing properties located primarily in Texas, and Oklahoma, and we own a substantial amount of well-servicing equipment.

We do not own any refinery or marketing facilities and do not currently own or lease any bulk storage facilities or pipelines other than adjacent to and used in connection with producing wells and the interests in certain gas gathering systems. All of our oil and gas properties and interests are located in the United States.

In the past, the supply of gas has exceeded demand on a cyclical basis, and we are subject to a combination of shut-ins and/or reduced takes of gas production during summer months. Prolonged shut-ins could result in reduced field operating income from properties in which we act as operator.

Exploration for oil and gas requires substantial expenditures, particularly in exploratory drilling in undeveloped areas, or “wildcat drilling.” As is customary in the oil and gas industry, substantially all of our exploration and development activities are conducted through joint drilling and operating agreements with others engaged in the oil and gas business.

Summaries of our oil and gas drilling activities, oil and gas production, and undeveloped leasehold, mineral, and royalty interests are set forth under Item 2., “Properties”, below. Summaries of our oil and gas reserves, future net revenue and present value of future net revenue are also set forth under Item 2., “Properties—Reserves”, below.

Well Operations

Our operations are conducted through our principal offices in Houston, Texas, and district offices in Houston and Midland, Texas, and Oklahoma City, Oklahoma. We currently operate 628 wells, including producing, saltwater disposal, injection, and supply wells: 96 through the Houston office, 316 through the Midland office, and 216 through the Oklahoma City office. We own a majority interest in nearly all of our operated wells.

We operate wells according to operating agreements that govern the relationship between us, as operator, and the other owners of working interests in the properties and joint venture participants. For each operated well, we receive monthly fees that are competitive in the areas of operations and we also are reimbursed for expenses incurred in connection with well operations.

The Partnerships, Trusts and Joint Ventures

Since 1975, PEMC acted as managing general partner of various partnerships, trusts and joint ventures. As we entered into 2021, we had one partnership and one trust remaining. During 2021 the remaining partnership and trust were liquidated

Regulation

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by the United States Congress (“Congress”), state governments, the Federal Energy Regulatory Commission (the “FERC”) and other federal and state regulatory agencies and federal, state and local courts. We cannot predict when or whether any such proposals may become effective. We do not believe that such action or proposal would have a material disproportionate effect on us as compared to similarly situated competitors.

Regulation Affecting Production

As described above, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. In addition, all of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. These laws and regulations may limit the number of oil and natural gas wells we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or limit the number of locations we can drill.

The failure to comply with the rules and regulations of oil and natural gas production and related operations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation Affecting Sales and Transportation of Commodities

Sales prices for oil, natural gas and NGLs are not currently regulated and therefore are dictated by the prevailing market prices. Although prices of these energy commodities are currently unregulated, Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil and natural gas, or the prices charged for these commodities, might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Sales of oil and natural gas may be subject to certain state and federal reporting requirements.

The price and terms of service of transportation of commodities, including access to pipeline transportation capacity, are subject to extensive federal and state regulation. Such regulation may affect the marketing of oil and natural gas produced, as well as the revenues received for sales of such production. Gathering systems may be subject to state ratable take statutes and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil and natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase, or accept for gathering, without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes may affect whether and to what extent gathering capacity is available for oil and natural gas production, if any, of the drilling program and the cost of such capacity. Further, state laws and regulations govern rates and terms of access to intrastate pipeline systems, which may similarly affect market access and cost.

To the extent that the Company enters into transportation contracts with pipelines that are subject to the United States Federal Energy Regulatory Commission ("FERC") regulation, the Company is subject to FERC requirements related to use of such capacity. Any failure on the Company's part to comply with FERC's regulations and policies related to pipeline transportation, reporting requirements or other regulations, and any failure to comply with a FERC-related pipeline's tariff, could result in the imposition of civil and criminal penalties. In addition, any changes in FERC or state regulations or requirements on pipeline transportation may result in increased transportation costs on pipelines that are subject to such regulation, thereby negatively impacting the Company's profitability.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment and occupational health and safety. These laws and regulations may, among other things: (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and (v) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transportation, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our purchasers. Moreover, accidental releases or spills may occur in the course of our operations and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While compliance with existing environmental laws and regulations has not had a material adverse effect on our operations to date, we can provide no assurance that this will continue in the future.

The following is a summary of the more significant existing and proposed environmental, occupational health and safety laws and regulations to which our business operations are or may be subject to and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

The Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes.

Pursuant to rules issued by the U.S. Environmental Protection Agency (the "EPA"), individual state governments administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. A change in the classification of exploration and production wastes has the potential to significantly increase our waste disposal costs to manage, which in turn will result in increased operating costs and could adversely impact our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and former owners and operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, 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. We generate materials in the course of our operations that may be regulated as hazardous substances. Despite the "petroleum exclusion" of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state and local laws. Under such laws, we could be required to undertake investigatory, response, or corrective measures, which could include soil and groundwater sampling, the removal of previously disposed substances and wastes, the cleanup of contaminated property, or remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (the "CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including wetland areas, is prohibited, except in accordance with the terms of a permit issued by the EPA, the U.S. Army Corps of Engineers (the "USACE") or an analogous state agency. In September 2015, the EPA and the USACE issued a final rule redefining the scope of the EPA's and the USACE's jurisdiction under the CWA with respect to certain types of waterbodies and classifying these waterbodies as regulated wetlands (the "WOTUS" rule). Several legal challenges to the rule followed, along with attempts to stay implementation of the WOTUS rule following the change in U.S. presidential administrations. Currently, the WOTUS rule is active in

22 states and enjoined in 28 states. However, in December 2018, the EPA and the USACE proposed changes to regulations under the CWA that would provide discrete categories of jurisdictional waters and tests for determining whether a particular waterbody meets any of those classifications. Several groups have already announced their intent to challenge the proposed WOTUS replacement rule. Therefore, the scope of jurisdiction under the CWA is uncertain at this time. To the extent the original WOTUS rule or any replacement rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. In addition, federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. We do not expect the costs to comply with the requirements of the CWA to have a material adverse effect on our operations.

The Oil Pollution Act of 1990 amends the CWA and establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, this law requires owners and operators of facilities that store oil above specified threshold amounts to develop and implement spill prevention, control and countermeasures plans.

Safe Drinking Water Act and Saltwater Disposal Wells

In the course of our operations, we produce water in addition to oil and natural gas. Water that is not recycled or otherwise disposed of on the lease may be sent to saltwater disposal wells for injection into subsurface formations. Underground injection operations are regulated under the federal Safe Drinking Water Act and permitting and enforcement authority may be delegated to state governments. In Texas, the Texas Railroad Commission ("RRC") regulates the disposal of produced water by injection well. The RRC requires operators to obtain a permit from the agency for the operation of saltwater disposal wells and establishes minimum standards for injection well operations. In response to recent seismic events near underground injection wells used for the disposal of oil and natural gas-related waste waters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or placed volumetric injection limits on existing wells or imposed moratoria on the use of such injection wells. In response to concerns related to induced seismicity, regulators in some states have already adopted or are considering additional requirements related to seismic safety. For example, the RRC has adopted rules for injection wells to address these seismic activity concerns in Texas. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. More stringent regulation of injection wells could lead to reduced construction or the capacity of such wells, which could in turn impact the availability of injection wells for disposal of wastewater from our operations. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability. The costs associated with the disposal of proposed water are commonly incurred by all oil and natural gas producers, however, and we do not believe that these costs will have a material adverse effect on our operations.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard for ozone from 75 to 70 parts per billion. The EPA approved final attainment/nonattainment designations with the new ozone standards in July 2018 and currently all of the areas in which we operate are in attainment with such standards. However, state implementation of these revised air quality standards or a change in the attainment status of the areas in which we operate could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. Separately, in June 2016, the EPA finalized a rule regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. The EPA has also adopted new rules under the Clean Air Act that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as “green completions.” These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. The EPA expanded on its emission standards for volatile organic compounds in June 2016 with the issuance of first-time standards, known as Subpart OOOOa, to address emissions of methane from equipment and processes across the oil and natural gas source category, including hydraulically fractured oil and natural gas well completions. Following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result of these developments, substantial uncertainty exists with respect to implementation of the EPA’s 2016 methane rule. However, given the long-term trend toward increasing regulation, future federal methane regulation of the oil and gas industry remains a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities. These and other air pollution control and permitting requirements have the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant. We do not believe that compliance with such requirements, however, will have a material adverse effect on our operations.

Regulation of Greenhouse Gas Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) endanger public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish Prevention of Significant Deterioration (“PSD”), construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards for these emissions. EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our operations. Also, as noted above, the EPA has promulgated a New Source Performance Standard related to methane emissions from the oil and natural gas source category.

Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Finally, it should also be noted that many scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic events; if any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, resulting in new legislative and regulatory initiatives that seek to increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Further, the EPA finalized regulations under the CWA in June 2016 that prohibit wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of, or prohibiting, drilling or hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may be required to incur significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from drilling wells.

If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Endangered Species Act and Migratory Birds

The federal Endangered Species Act (“ESA”) and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service (the “FWS”) may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. Moreover, as a result of a 2011 settlement agreement, the FWS was required to make a determination on listing of more than 250 species as endangered or threatened under the FSA by no later than completion of the agency’s 2017 fiscal year. The FWS missed the deadline but reportedly continues to review new species for protected status under the ESA pursuant to the settlement agreement. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Recently, there have been renewed calls to review protections currently in place for the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. The designation as threatened or endangered of previously unprotected species in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our development and production activities that could have a material adverse impact on our ability to develop and produce our reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the Occupational Safety and Health Administration ("OSHA") and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and natural gas activities and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal, or litigation, which, in certain cases, can delay or halt projects and cease production or operation of wells, pipelines and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. However, this insurance is limited to activities at the well site, and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a material adverse effect on our financial condition and operations.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2022, nor do we anticipate that such expenditures will be material in 2023.

Competition and Markets

The business of acquiring producing properties and non-producing leases suitable for exploration and development is highly competitive. Our competition, in our efforts to acquire both producing and non-producing properties, include oil and gas companies, independent concerns, income programs and individual producers and operators, many of which have financial resources, staffs and facilities substantially greater than those available to us. Furthermore, domestic producers of oil and gas must not only compete with each other in marketing their output, but must also compete with producers of imported oil and gas and alternative energy sources such as coal, nuclear power and hydroelectric power. Competition among petroleum companies for favorable oil and gas properties and leases can be expected to increase. The Company also faces competition from companies that supply alternative sources of energy, such as wind, solar and other renewables. Competition will increase as alternative energy technology becomes more reliable and governments throughout the world support or mandate the use of such alternative energy, The availability of a ready market for any oil and gas produced by us at acceptable prices per unit of production will depend upon numerous factors beyond our control, including the extent of domestic production and importation of oil and gas, the proximity of our producing properties to gas pipelines and the availability and capacity of such pipelines, the marketing of other competitive fuels, fluctuation in demand, governmental regulation of production, refining, transportation and sales, general national and worldwide economic conditions, and use and allocation of oil and gas and their substitute fuels. There is no assurance that we will be able to market all of the oil or gas produced by us or that favorable prices can be obtained for the oil and gas production.

We derive our revenue and cash flow principally from the sale of oil, natural gas and NGLs. As a result, our revenues are determined, to a large degree, by prevailing prices for crude oil, natural gas and NGLs. We sell our oil and natural gas on the open market at prevailing market prices or through forward delivery contracts. Because some of our operations are located outside major markets, we are directly impacted by regional prices regardless of Henry Hub, WTI or other major market pricing. The market price for oil, natural gas and NGLs is dictated by supply and demand; consequently, we cannot accurately predict or control the price we may receive for our oil, natural gas and NGLs.

We have an active hedging program to mitigate risk regarding our cash flow and to protect returns from our development activity in the event of decreases in the prices received for our production; however, hedging arrangements may expose us to risk of financial loss in some circumstances and may limit the benefit we would receive from increases in the prices for oil, natural gas and NGLs.

Oil and Gas Industry Considerations

The COVID-19 pandemic resulted in a severe worldwide economic downturn, significantly disrupting the demand for oil throughout the world, and created significant volatility, uncertainty and turmoil in the oil and gas industry. The decrease in demand for oil, combined with excess supply of oil and related products, resulted in oil prices declining significantly beginning in late February 2020. Since mid-2020, oil prices have improved, with demand steadily increasing despite the uncertainties surrounding the COVID-19 variants, and related responses by governments worldwide with regards to travel restrictions, business closures and other restrictions, which have continued to inhibit a full global demand recovery. In addition, worldwide oil inventories, from a historical perspective, remain low and concerns exist with the ability of OPEC and other oil producing nations to meet forecasted future oil demand growth, with many OPEC countries not able to produce at their OPEC agreed upon quota levels due to their limited capital investments directed towards developing incremental oil supplies over the past few years. Furthermore, sanctions, import bans and price caps on Russia have been implemented by various countries in response to the war in Ukraine, further impacting global oil supply. As a result of these and other oil and gas supply constraints, the world has experienced significant increases in energy costs. During December 2022, OPEC announced a continuation of its 2 MMBOPD production cut that started in November 2022 related to the uncertainty surrounding the global economy and future oil demand. As a result of the current global supply and demand imbalances, oil and gas prices have remained strong with average NYMEX oil and NYMEX gas prices for the three months ended December 31, 2022 being $82.64 per Bbl and $6.26 per Mcf, respectively, as compared to $77.19 per Bbl and $5.84 per Mcf, respectively, for the same period in 2021. In addition, the ongoing pandemic, combined with the Russia/Ukraine conflict, has resulted in global supply chain disruptions, which has led to significant cost inflation and the potential for a global recession. Specifically, the Company’s 2022 capital program was impacted by higher than expected inflation in steel, diesel and chemical prices, among other items. Global oil price levels and inflationary pressures will ultimately depend on various factors that are beyond the Company’s control, such as (i) the ability of OPEC and other oil producing nations to manage the global oil supply, (ii) the impact of sanctions and import bans on production from Russia, (iii) the timing and supply impact of any Iranian sanction relief on their ability to export oil, (iv) the effectiveness of responses by businesses and governments to combat any additional outbreaks of the COVID-19 virus and their impact on domestic and worldwide demand, (v) the global supply chain constraints associated with manufacturing and distribution delays, (vi) oilfield service demand and cost inflation, (vii) political stability of oil consuming countries and (viii) increasing expectations that the world may be heading into a global recession.

The Company continues to assess and monitor the impact of these factors and consequences on the Company and its operations.

Major Customers

The Company sells its oil and gas production to a number of direct purchasers under direct contracts or through other operators under joint operating agreements. Listed below are the percent of the Company's total oil and gas sales made which represented more than 10% of the Company's oil and gas sales in the year 2022.

Oil Purchasers:	
Apache Corporation	55%
Plains All American Inc.	16%
Gas Purchasers:	
Apache Corporation	58%
Targa Pipeline Mid-Continent West Tex, LLC	11%

Although there are no long-term purchasing agreements with these purchasers, we believe that they will continue to purchase our oil and gas products and, if not, could be readily replaced by other purchasers.

Employees

At December 31, 2022, we had 114 full time employees, 28 of whom were employed at our principal offices in Houston, Texas, at the offices of Prime Operating Company, Eastern Oil Well Service Company and EOWS Midland Company, and 86 employees who were primarily involved in our district operations in Midland, Texas, Elmore City and Oklahoma City, Oklahoma.

Item 1A. RISK FACTORS.

The prices of oil, NGL and gas are highly volatile. A sustained decline in these commodity prices could materially and adversely affect the Company's business, financial condition and results of operations.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and oil. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Natural gas prices, based on the twelve-month average of the first of the month Henry Hub index price, were $6.358 per MMBTU in 2022 as compared to $3.598 per MMBTU in 2021, and have averaged $5.954 per MMBTU for the first three months of 2023. Oil prices, based on West Texas Intermediate(WTI) Light Sweet Crude first of the month prices, averaged $93.67 per barrel in 2022 as compared to $66.56 per barrel in 2022, and in the first three months of 2023, the first of the month price has averaged $90.97 per barrel.

Any substantial or extended decline in future natural gas or crude oil prices would have a material adverse effect on our future business, financial condition, results of operations, cash flows, liquidity or ability to finance planned capital expenditures and commitments. Furthermore, substantial, extended decreases in natural gas and crude oil prices may cause us to delay or postpone a significant portion of our exploration, development and exploitation projects or may render such projects uneconomic, which may result in significant downward adjustments to our estimated proved reserves and could negatively impact our ability to borrow and cost of capital and our ability to access capital markets, increase our costs under our revolving credit facility, and limit our ability to execute aspects of our business plans.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- the level of consumer product demand;

- weather conditions;
- political conditions in natural gas and oil producing regions, including the Middle East, Africa and South America;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price levels and quantities of foreign imports;
- actions of governmental authorities;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for natural gas and oil;
- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- the price, availability and acceptance of alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and natural gas;
- variations between product prices at sales points and applicable index prices;
- overall economic conditions and
- global or national health concerns, including the outbreak of pandemic or contagious disease, such as the coronavirus.

In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write down, as a noncash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European, Asian and the United States financial markets have in the past contributed, and may in the future contribute, to economic uncertainty and diminished expectations for the global economy. In addition, continued hostilities in the Middle East, the occurrence or threat of terrorist attacks in the United States or other countries and global or national health concerns could adversely affect the global economy. These factors, combined with volatility in commodity prices, business and consumer confidence and unemployment rates, may precipitate an economic slowdown. Concerns about global economic growth may have an adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition. These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. If natural gas and oil prices decline significantly for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

Financial difficulties encountered by our oil and natural gas purchasers, third-party operators or other third parties could decrease cash flow from operations and adversely affect our exploration and development activities.

We derive essentially all of our revenues from the sale of our oil, natural gas and NGLs to unaffiliated third-party purchasers, independent marketing companies and midstream companies. Any delays in payments from such purchasers caused by their financial difficulties, including those resulting from the impacts of COVID-19 and its impact on the global economy, will have an immediate negative effect on our results of operations and cash flows.

Additionally, liquidity and cash flow problems encountered by our working interest co-owners or the third-party operators of our non-operated properties may prevent or delay the drilling of a well or the development of a project. Our working interest co-owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a working interest owner, we could be required to pay the working interest owner's share of the project costs.

The shut-in of our wells could negatively impact our production, liquidity, and, ultimately, our operations, results, and performance.

Our production depends, in part, upon our wells that are capable of commercial production not being shut-in (i.e., suspended from production). The lack of availability of capacity on third-party systems and facilities or the shut-in of an oil field's production could result in the shut-in of our wells

The producing wells in which we have an interest occasionally experience reduced or terminated production. These curtailments can result from mechanical failures, contract terms, pipeline and processing plant interruptions, market conditions, operator priorities, and weather conditions. These curtailments can last from a few days to many months, any of which could have an adverse effect on our results of operations.

If we experience low oil production volumes due to the shut-in of our wells or other mechanical failures or interruptions, it would impact our ability to generate cash flows from operations and we could experience a reduction in our available liquidity. A decrease in our liquidity could adversely affect our ability to meet our anticipated working capital, debt service, and other liquidity needs.

Drilling natural gas and oil wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors beyond our control, including:

- decreases in natural gas and oil prices;
- unexpected drilling conditions, pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- loss of title or other title related issues;
- surface access restrictions;
- lack of available gathering or processing facilities or delays in the construction thereof;
- compliance with, or changes in, governmental requirements and regulation, including with respect to wastewater disposal, discharge of greenhouse gases and fracturing; and

- shortages or delays in the availability of required goods or services such as drilling rigs or crews, the delivery of equipment and the availability of sufficient water for drilling operations.

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate within a particular geographic area may decline. We may be unable to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may be unable to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects.

These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive natural gas or oil.

Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently uncertain, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. As a result, estimates of different engineers may vary. In addition, the extent, quality and reliability of this technical data can vary. The differences in the reserve estimation process are substantially due to the geological conditions in which the wells are drilled. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board ("FASB") in Accounting Standards Codification ("ASC") Section 932 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

The Company's expectations for future drilling activities will be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

The Company has identified drilling locations and prospects for future drilling opportunities, including development and infill drilling activities. These drilling locations and prospects represent a significant part of the Company's future drilling plans. The Company's ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, access to and availability of equipment, services, resources and personnel and drilling results. Changes in the laws or regulations on which the Company relies in planning and executing its drilling programs could adversely impact the Company's ability to successfully complete those programs. For example, under current Texas laws and regulations the Company may receive permits to drill, and may drill and complete, certain horizontal wells that traverse one or more units and/or leases; a change in those laws or regulations could adversely impact the Company's ability to drill those wells. Because of these uncertainties, the Company cannot give any assurance as to the timing of these activities or that they will ultimately meet the Company's expectations for success. As such, the Company's actual drilling activities may materially differ from the Company's current expectations, which could have a significant adverse effect on the Company's proved reserves, financial condition and results of operations.

Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable.

In general, the production rate of natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in natural gas and oil production and lower revenues and cash flow from operations. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Low natural gas and oil prices may further limit the kinds of reserves that we can develop economically. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

Exploration, development and exploitation activities involve numerous risks that may result in dry holes, the failure to produce natural gas and oil in commercial quantities and the inability to fully produce discovered reserves.

We are continually identifying and evaluating opportunities to acquire natural gas and oil properties. We may not be able to successfully consummate any acquisition, to acquire producing natural gas and oil properties that contain economically recoverable reserves, or to integrate the properties into our operations profitably.

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, if at all.

We rely upon access to our revolving credit facility as a source of liquidity for any capital requirements not satisfied by cash flow from operations or other sources. Future challenges in the global financial system, including the capital markets, may adversely affect our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we desire, or need, to raise capital, which could have an impact on our flexibility to react to changing economic and business conditions. Adverse economic and market conditions could adversely affect the collectability of our trade receivables and cause our commodity hedging counterparties to be unable to perform their obligations or to seek bankruptcy protection. Future challenges in the economy could also lead to reduced demand for natural gas which could have a negative impact on our revenues.

Our debt agreements also require compliance with covenants to maintain specified financial ratios. If the price that we receive for our natural gas and oil production further deteriorates from current levels or continues for an extended period, it could lead to further reduced revenues, cash flow and earnings, which in turn could lead to a default under those ratios. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period. A prolonged period of decreased natural gas and oil prices or a further decline could further increase the risk of our inability to comply with covenants to maintain specified financial ratios. In order to provide a margin of comfort with regard to these financial covenants, we may seek to reduce our capital expenditure plan, sell non-strategic assets or opportunistically modify or increase our derivative instruments to the extent permitted under our debt agreements. In addition, we may seek to refinance or restructure all or a portion of our indebtedness. We cannot assure you that we will be able to successfully execute any of these strategies, and such strategies may be unavailable on favorable terms or not at all.

The borrowing base under our revolving credit facility may be reduced in light of recent commodity price declines, which could limit us in the future.

The borrowing base under our revolving credit facility is currently $60 million, and lender commitments under our revolving credit facility are $300 million. The borrowing base is redetermined semi-annually under the terms of the revolving credit facility. In addition, either we or the lenders may request an interim redetermination twice a year or in conjunction with certain acquisitions or sales of oil and gas properties. Our borrowing base may decrease as a result of lower natural gas or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for other reasons set forth in our revolving credit agreement. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, our ability to borrow under our revolving credit facility may be limited and we could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets to meet our obligations, including any such debt repayment obligations.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our growth rate.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our business plan, we considered allocating capital and other resources to various aspects of our businesses including well-development (primarily drilling), reserve acquisitions, exploratory activity, corporate items and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2023 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2023 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, oil spills, greenhouse gas or methane emissions and explosions of natural gas transmission lines, may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

We face a variety of hazards and risks that could cause substantial financial losses.

Our business involves a variety of operating risks, including:

- blowouts, cratering and explosions;
- mechanical problems;
- uncontrolled flows of natural gas, oil or well fluids;
- formations with abnormal pressures;
- pollution and other environmental risks; and
- natural disasters.

Our operation of natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures.

We may not be insured against all of the operating risks to which we are exposed.

We maintain insurance coverage against certain, but not all, hazards that could arise from our operations. Such insurance is believed to be reasonable for the hazards and risks faced by us. We do not carry business interruption insurance. In addition, pollution and environmental risks are not fully insurable.

We maintain for our operations total excess liability insurance with limits of $20 million per occurrence and in the aggregate covering certain general liability and certain “sudden and accidental” environmental risks with a deductible of $100,000 per occurrence, subject to all terms, restrictions and sub-limits of the policies. We also maintain general liability insurance limits of $1 million per occurrence and $2 million in the aggregate.

We have several policies that cover environmental risks. We have environmental coverage under the per occurrence and aggregate limits of our general and umbrella liability policies (for a twelve-month term). These policies provide third-party surface cleanup, bodily injury and property damage coverage, and defense costs when a pollution event is sudden and accidental and is discovered within thirty days of commencement and reported to the insurance company within ninety days of discovery. This is standard coverage in oil and gas insurance policies.

We seek to protect ourselves from some but not all operating hazards through insurance coverage. However, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our customers and contractors. However, customers and contractors who provide contractual indemnification protection may not in all cases maintain adequate insurance to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a customer to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may not be able to maintain adequate insurance in the future at rates we consider reasonable.

From time to time, a small number of our contractors have requested contractual provisions that require us to respond to third-party claims. In some of these instances we have accepted the risk with the understanding that it would be covered under our current coverage. We evaluate these risk-transferring negotiations cautiously, and we feel that we have adequately mitigated this risk through existing coverage or acquiring supplemental coverage when appropriate.

Laws and regulations regarding hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions, delays or cancellations and have a material adverse effect on the Company's production.

Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons from tight formations. The Company conducts hydraulic fracturing in its drilling and completion programs. The process involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to stimulate oil and gas production. The process is typically regulated by state oil and gas commissions or similar agencies, but in recent years, several federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. For example, in 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Additionally, the EPA has asserted regulatory authority pursuant to the SDWA's UIC program over hydraulic fracturing activities involving the use of diesel and has issued guidance covering such activities. Moreover, the EPA has published an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing under the Toxic Substances Control Act and has implemented a final rule under the CWA prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly-owned wastewater treatment plants. Also, the federal Bureau of Land Management ("BLM") published a final rule in 2015 that established new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. The BLM rescinded the 2015 rule in late 2017; however, litigation challenging the BLM's decision to rescind the 2015 rule remains pending in federal district court.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the additives used in the hydraulic-fracturing process. In addition, certain states, including Texas where the Company operates, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, disposal and well-construction requirements on hydraulic-fracturing operations. For example, in April 2019, Colorado passed legislation reforming exploration and production activities by the oil and gas industry in the state including, among other things, revising the mission of the state oil and gas agency from fostering energy development in the state to instead focusing on regulating the industry in a manner that is protective of public health and safety and the environment, as well as authorizing cities and counties to regulate oil and gas operations within their jurisdictions as they do other development. While the Company does not conduct operations in Colorado, passage or enactment of similar legislation in other states in which it does operate could significantly increase the Company's operating costs and have a significant adverse effect on the Company's ability to conduct operations. States could elect to prohibit hydraulic fracturing or high volume hydraulic fracturing altogether, following the approach taken by the states of Vermont, Maryland and New York. Also, local land use restrictions, such as city ordinances, may be adopted to restrict or prohibit drilling in general or hydraulic fracturing in particular. In Texas, legislation was adopted providing that the regulation of oil and gas operations in Texas is under the exclusive jurisdiction of the state and thus preempts local regulation of those operations. Nonetheless, municipalities and political subdivisions in Texas continue to have the right to enact "commercially reasonable" regulations for surface activities.

In the event federal, state or local restrictions or bans pertaining to hydraulic fracturing are adopted in areas where the Company is currently conducting operations, or in the future plans to conduct operations, the Company may incur additional costs to comply with such requirements, experience restrictions, delays or cancellations in the pursuit of exploration, development or production activities, and perhaps be limited or precluded in the drilling of wells or in the volume that the Company is ultimately able to produce from its reserves; one or more of which developments could have a material adverse effect on the Company.

The Company's operations are subject to stringent environmental, oil and gas-related and occupational safety and health laws and regulations that could cause it to delay, curtail or cease its operations or expose it to material costs and liabilities.

The Company's operations are subject to stringent federal, state and local laws and regulations governing, among other things, the drilling of wells, rates of production, the size and shape of drilling and spacing units or proration units, the transportation and sale of oil, NGL and gas, and the discharging of materials into the environment and environmental protection. For example, state laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate development, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company's interest in the unitized properties. In addition, state conservation laws (i) establish maximum rates of production from oil and gas wells, (ii) generally prohibit the venting or flaring of gas and (iii) impose requirements regarding production rates. These laws and regulations may limit the amount of oil and gas the Company can produce from the Company's wells or limit the number of wells or the locations that the Company can drill.

In connection with its operations, the Company must obtain and maintain numerous environmental and oil and gas-related permits, approvals and certificates from various federal, state and local governmental authorities, and may incur substantial costs in doing so. The need to obtain permits has the potential to delay, curtail or cease the development of oil and gas projects. The Company may in the future be charged royalties on gas emissions or required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in 2015, the EPA issued a final rule under the CAA lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone from 75 parts per billion to 70 parts per billion under standards to provide protection of public health and welfare. In subsequent years, the EPA has issued area designations with respect to ground-level ozone and final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. State implementation of the revised NAAQS could, among other things, require installation of new emission controls on some of the Company's equipment, resulting in longer permitting timelines, and significantly increase the Company's capital expenditures and operating costs. In another example, the EPA and U.S. Army Corps of Engineers (the "Corps") released a final rule in 2015 outlining federal jurisdictional reach under the CWA over waters of the U.S., including wetlands. In 2017, the EPA and the Corps agreed to reconsider the 2015 rule and, thereafter, on October 22, 2019, the agencies published a final rule, which became effective on December 31, 2019, rescinding the 2015 rule. On January 23, 2020, the two agencies issued a final rule re-defining the Clean Water Act's jurisdiction over waters of the United States, which redefinition is narrower than found in the 2015 rule. Upon being published in the Federal Register and the passage of 60 days thereafter, the January 23, 2020 final rule will become effective, at which point the United States will be covered under a single regulatory scheme as it relates to federal jurisdictional reach over waters of the United States. However, there remains the expectation that the January 23, 2020 final rule also will be legally challenged in federal district court. To the extent that any challenge to the January 23, 2020 final rule is successful and the 2015 rule or a revised rule expands the scope of the Clean Water Act's jurisdiction in areas where the Company conducts operations, the Company could incur (i) delays, restrictions or prohibitions in the issuance of necessary permits, (ii) restrictions or cessations in the development or expansion of projects, or (iii) increases in the Company's capital expenditures and operating expenses by, for example, requiring installation of new emission controls on some of the Company's equipment, any one or more of which developments could have a material adverse effect on the Company's business, financial condition and results of operations.

Additionally, the Company's operations are subject to a number of federal and state laws and regulations, including the federal OSHA and comparable state statutes, whose purpose is to protect the health and safety of employees. Among other things, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in the Company's operations and that this information be provided to employees, state and local government authorities and citizens.

There can be no assurance that existing or future regulations will not result in a delay, curtailment or cessation of production or processing activities, result in a material increase in the costs of production, development, exploration or processing operations or materially and adversely affect the Company's future operations and financial condition. Noncompliance with these laws and regulations may subject the Company to sanctions, including administrative, civil or criminal penalties, remedial cleanups or corrective actions, delays in permitting or performance of projects, natural resource damages and other liabilities. Such laws and regulations may also affect the costs of acquisitions. In addition, these laws and regulations are subject to amendment or replacement in the future with more stringent legal requirements. Further, any delay, reduction or curtailment of the Company's development and producing operations due to these laws and regulations could result in the loss of acreage through lease expiration.

The nature of the Company's assets and production operations may impact the environment or cause environmental contamination, which could result in material liabilities to the Company.

The Company's assets and production operations may give rise to significant environmental costs and liabilities as a result of the Company's handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to its operations, and due to past industry operations and waste disposal practices. The Company's oil and gas business involves the generation, handling, treatment, storage, transport and disposal of wastes, hazardous substances and petroleum hydrocarbons and is subject to environmental hazards, such as oil and produced water spills, NGL and gas leaks, pipeline and vessel ruptures and unauthorized discharges of such wastes, substances and hydrocarbons, that could expose the Company to substantial liability due to pollution and other environmental damage. For example, drilling fluids, produced waters and certain other wastes associated with the Company's exploration, development and production of oil or gas are currently excluded under RCRA from the definition of hazardous waste. These wastes are instead regulated under RCRA's less stringent non-hazardous waste provisions. There have been efforts from time to time to remove this exclusion. For example, in response to a federal consent decree issued in 2016, the EPA was required during 2019 to determine whether certain Subtitle D criteria regulations required revision in a manner that could result in oil and gas wastes being regulated as RCRA hazardous waste. In April 2019, the EPA made a determination that such revision of the regulations was unnecessary. Any future loss of the RCRA exclusion could have a material adverse effect on the Company's results of operations and financial position.

The Company currently owns, leases or operates, and in the past has owned, leased or operated, properties that for many years have been used for oil and gas exploration and production activities, and petroleum hydrocarbons, hazardous substances and wastes may have been released on or under such properties, or on or under other locations, including off-site locations, where such substances have been taken for treatment or disposal. These wastes, substances and hydrocarbons may also be released during future operations. In addition, some of the Company's properties have been operated by predecessors or previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons were not under the Company's control. Joint and several strict liabilities may be incurred in connection with such releases of petroleum hydrocarbons, hazardous substances and wastes on, under or from the Company's properties. Private parties, including lessors of properties on which the Company operates and the owners or operators of properties adjacent to the Company's operations and facilities where the Company's petroleum hydrocarbons, hazardous substances or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as seek damages for noncompliance with environmental laws and regulations or for personal injury or damage to property or natural resources. Such properties and the substances disposed or released on or under them may be subject to CERCLA, RCRA and analogous state laws, which could require the Company to remove previously disposed substances, wastes and petroleum hydrocarbons, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination, the costs of which could have a material adverse effect on the Company's business, financial condition and results of operations.

The Company may not be able to recover some or any of these costs from sources of contractual indemnity or insurance, as pollution and similar environmental risks generally are not insurable or fully insurable, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance.

The Company's operations are subject to a number of risks arising out of concerns regarding the threat of climate change, including regulatory, political, litigation and financial risks, that could result in increased operating costs and costs of compliance, limit the areas in which oil and gas production may occur, reduce demand for the oil and gas the Company produces, and expose the Company to the risk of increased activism and decreased funding for the industry, while the potential physical effects of climate change could disrupt the Company's production and cause it to incur significant costs in preparing for or responding to those effects.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. Numerous initiatives have been proposed and are expected to continue to be proposed at the international, national, regional and state levels of government to monitor and limit existing sources of GHG emissions as well as to restrict or eliminate emissions from new sources. As a result, the Company's operations are subject to a series of regulatory, political, litigation and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, (i) establish construction and operating permit reviews for GHG emissions from certain large stationary sources, (ii) require the monitoring and annual reporting of GHG emissions from certain petroleum and gas system sources in the United States, (iii) implement CAA emission standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and gas sector, and (iv) together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. Additionally, various states, groups of states, and other countries have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there is a non-binding agreement, the United Nations sponsored "Paris Agreement," for nations to limit their GHG emissions through individually-determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates seeking the office of the President of the United States in 2020. Critical declarations made by one or more candidates running for President include proposals to ban hydraulic fracturing of oil and gas wells and ban new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions that could be pursued by presidential candidates may include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, the reversal of the United States' withdrawal from the Paris Agreement in November 2020 and reinstatement of the ban on oil exports.

Litigation risks are also increasing, as a number of cities, local governments or other persons have sought to bring suit against oil and gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also financial risks for fossil fuel producers as stockholders or bondholders currently invested in fossil-fuel energy companies concerned about the threat of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, investing and lending practices of various investment firms and institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the Paris Agreement, and foreign citizenry concerned about the threat of climate change not to provide funding for fossil fuel producers. For example, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, to divest of fossil fuel equities and lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and gas sector or otherwise restrict the areas in which this sector may produce oil and gas or generate GHG emissions could result in increased compliance and consumption costs, and thereby reduce demand for the oil and gas the Company produces. Additionally, political, litigation and financial risks could result in the restriction or cancellation of production activities, incurring liability for infrastructure damages as a result of climate changes, or impairing the Company’s ability to continue to operate in an economic manner. Finally, if increasing concentrations of GHGs in the Earth’s atmosphere were to result in significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events, then such effects could have a material adverse effect on the Company’s exploration and production operations.

In addition, companies in the oil and gas industry have been the target of activist efforts from both individuals and non-governmental organizations, including instituting litigation and supporting political or regulatory efforts to, among other things, limit or ban hydraulic fracturing, restrict or ban certain operating practices, including the disposal of waste materials, such as hydraulic fracturing fluids and produced water, deny or delay drilling permits, prohibit the venting or flaring of gas, reduce access of the oil and gas industry to federal and state government lands, and delay or cancel oil and gas developmental or expansion projects. The Company may need to incur significant costs associated with responding to these initiatives, and complying with any resulting additional legal or regulatory requirements could have a material adverse effect on the Company’s business, financial condition, cash flows and results of operations.

Laws and regulations pertaining to protection of threatened and endangered species or to critical habitat, wetlands and natural resources could delay, restrict or prohibit the Company’s operations and cause it to incur substantial costs that may have a material adverse effect on the Company’s development and production of reserves.

The federal ESA and comparable state laws were established to protect endangered and threatened species. Under the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. Similar protections are offered to migratory birds under the Federal Migratory Bird Treaty Act. Oil and gas operations in the Company’s operating areas may be adversely affected by seasonal or permanent restrictions imposed on drilling activities by the U.S. Fish and Wildlife Services (the

"FWS") that are designed to protect various wildlife, which may materially restrict the Company's access to federal or private land use. Permanent restrictions imposed to protect endangered and threatened species could prohibit drilling in certain areas, impact suppliers of critical materials or services, or require the implementation of expensive mitigation measures. Additionally, federal statutes, including the CWA, the OPA and CERCLA, as well as comparable state laws, prohibit certain actions that adversely affect critical habitat, wetlands and natural resources. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling, construction or releases of petroleum hydrocarbons, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties.

Moreover, as a result of one or more settlements entered into by the FWS, the agency is required to make determinations on the potential listing of numerous species as endangered or threatened under the ESA. The designation of previously unprotected species as threatened or endangered in areas where the Company conducts operations could cause the Company to incur increased costs arising from species protection measures or could result in delays, restrictions or prohibitions on its development and production activities that could have a material adverse effect on the Company's ability to develop and produce reserves.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Our ability to sell our natural gas and oil production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our natural gas and oil production depends on a number of factors beyond our control, including the availability and capacity of transportation and processing facilities. Our failure to obtain these services on acceptable terms could materially harm our business.

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record.

Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry.

We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of increases in prices for natural gas and oil.

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production in all of our regions. These hedging arrangements limit the benefit to us of increases in prices. While there are many different types of derivatives available, we generally utilize put options and swap agreements to attempt to manage price risk more effectively.

The put options used to establish floor prices for a fixed volume of production during a certain time period. They provide for payments from the counterparties if the index price falls below the floor. The swap agreements call for payments to, or receipts from, counterparties based on whether the index price for the period is greater or less than the fixed price established for that period when the swap is put in place. These arrangements limit the benefit to us of increases in prices. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty is unable to satisfy its obligations
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

The CFTC has promulgated regulations to implement statutory requirements for swap transactions. These regulations are intended to implement a regulated market in which most swaps are executed on registered exchanges or swap execution facilities and cleared through central counterparties. While we believe that our use of swap transactions exempt us from certain regulatory requirements, the changes to the swap market due to increased regulation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps. If we reduce our use of swaps as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to extensive federal, state and local laws and regulations, including tax laws and regulations and those relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These laws and regulations can adversely affect the cost, manner or feasibility of doing business. Many laws and regulations require permits for the operation of various facilities, and these permits are subject to revocation, modification and renewal. Governmental authorities have the power to enforce compliance with their regulations, and violations could subject us to fines, injunctions or both. These laws and regulations have increased the costs of planning, designing, drilling, installing and operating natural gas and oil facilities. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. Risks of substantial costs and liabilities related to environmental compliance issues are inherent in natural gas and oil operations. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from natural gas and oil production, would result in substantial costs and liabilities.

A failure of technology systems, data breach or cyberattack could materially affect our operations.

Our information technology systems may be vulnerable to security breaches, including those involving cyberattacks using viruses, worms or other destructive software, process breakdowns, phishing or other malicious activities, or any combination of the foregoing. Such breaches could result in unauthorized access to information, including customer, employee, or other confidential data. We do not carry insurance against these risks, although we do invest in security technology, perform penetration tests, and design our business processes to attempt to mitigate the risk of such breaches. However, there can be no assurance that security breaches will not occur. Moreover, the development and maintenance of these measures requires continuous monitoring as technologies change and security measures evolve. We have experienced, and expect to continue to experience, cyber security threats and incidents, none of which has been material to us to date. However, a successful breach or attack could have a material negative impact on our operations or business reputation and subject us to consequences such as litigation and direct costs associated with incident response.

Information technology solution failures, network disruptions, breaches of data security and cyberattacks could disrupt our operations by causing delays, impeding processing of transactions and reporting financial results, resulting in the unintentional disclosure of customer, employee or our information, or damage to our reputation. A system failure, data security breach or cyberattack could have a material adverse effect on our financial condition, results of operations or cash flows. In the past, we have experienced data security breaches resulting from unauthorized access to our e-mail systems, which to date have not had a material impact on our business; however, there is no assurance that such impacts will not be material in the future.

Item 1B. UNRESOLVED STAFF COMMENTS.

We are a smaller reporting company and therefore no response is required pursuant to this Item.

Item 2. PROPERTIES.

Our executive offices, as well as offices of Prime Operating Company, Eastern Oil Well Service Company and EOWS Midland Company are located in leased premises in Houston, Texas.

We maintain district offices in Midland, Texas and Oklahoma City, Oklahoma and have field offices in Carrizo Springs and Midland, Texas, as well as, Elmore City, Oklahoma.

Substantially all of our oil and gas properties are subject to a mortgage given to collateralize indebtedness or are subject to being mortgaged upon request by our lenders for additional collateral.

The information set forth below concerning our properties, activities, and oil and gas reserves includes our interests in affiliated entities.

The following table sets forth the exploratory and development drilling experience with respect to wells in which we participated during the three years ended December 31, 2022.

	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Oil	—	—	—	—	—	—
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Development:						
Oil	8	0.76	13	4.73	1	0.1
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total:						
Oil	8	0.76	13	4.73	1	0.1
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
	8	0.76	13	4.73	1	0.1

Oil and Gas Production

As of December 31, 2022, we had ownership interest in the following number of gross and net producing oil and gas wells(1).

	Gross	Net
Producing Wells(1)	1,108	498

(1) A gross well is a well in which a working interest is owned. A net well is the sum of the fractional revenue interests owned in gross wells.

The following table shows our net production of oil, NGL and natural gas for each of the three years ended December 31, 2022. “Net” production is net after royalty interests of others are deducted and is determined by multiplying the gross production volume of properties in which we have an interest by the percentage of the leasehold, mineral or royalty interest owned by us.

	2022	2021	2020
Oil (barrels)	939,000	738,000	727,000
NGL (barrels)	417,000	416,000	435,000
Gas (Mcf)	3,325,000	3,236,000	3,374,000

The following table sets forth our average sales prices together with our average production costs per unit of production for the three years ended December 31, 2022.

	2022	2021	2020
Average sales price per barrel of oil	$96.70	$68.39	$38.02
Average sales price per barrel of NGL	$35.70	$26.97	$11.22
Average sales price per Mcf of natural gas	$ 5.54	$ 3.53	$ 1.24
Average production costs per net equivalent barrel of oil(1)	$16.07	$13.76	$12.25

(1) Net equivalent barrels are computed at a rate of 6 Mcf per barrel and costs exclude production taxes.

Average oil, NGL and gas prices received including the impact of derivatives were:

	2022	2021	2020
Average sales price per barrel of oil	$87.77	$64.04	$45.79
Average sales price per barrel of NGL	$35.70	$26.97	$11.22
Average sales price per Mcf of natural gas	$ 4.44	$ 2.97	$ 1.38

Acreage

The following table sets forth the approximate gross and net undeveloped acreage in which we have leasehold and mineral interests as of December 31, 2022. "Undeveloped acreage" is that acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Leasehold acreage	88,599	24,029	—	—	88,599	24,029
Mineral fee acreage	1,640	117	19,257	417	20,897	534
Total	90,239	24,146	19,257	417	109,496	24,563

Total Net Undeveloped Acreage Expiration

In the event that production is not established, or we take no action to extend or renew the terms of our leases, our net undeveloped acreage that will expire over the next three years, as of December 31, 2022, is zero acres for the year ending December 31, 2023, zero in 2024, and zero acres in 2025.

Reserves

Our interests in proved developed and undeveloped oil and gas properties have been evaluated by Ryder Scott Company, L.P. for each of the three years ended December 31, 2022. The professional qualifications of the technical persons primarily responsible for overseeing the preparation of the reserve estimates can be found in Exhibit 99.1, the Ryder Scott Company, L.P. Report on Registrant's Reserves Estimates. In matters related to the preparation of our reserve estimates, our district managers report to the Engineering Data manager, who maintains oversight and compliance responsibility for the internal reserve estimate process and provides oversight for the annual preparation of reserve estimates of 100% of our year-end reserves by our independent third-party engineers, Ryder Scott Company, L.P. The members of our district and central groups consist of degreed engineers and geologists with between approximately twenty and thirty-five years of industry experience, and between eight and twenty-five years of experience managing our reserves. Our Engineering Data manager, the technical person primarily responsible for overseeing the preparation of reserves estimates, has over thirty years of experience, holds a Bachelor degree in Geology and an MBA in finance and is a member of the Society of Petroleum Engineers and American Association of Petroleum Geologist. See Part II, Item 8 "Financial Statements and Supplementary Data", for additional discussions regarding proved reserves and their related cash flows. All of our reserves are located within the continental United States. The following table summarizes our oil and gas reserves at each of the respective dates:

	Reserve Category											
	Proved Developed				Proved Undeveloped				Total			
As of December 31,	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe)
2020	2,684	2,258	13,633	7,214	1,784	787	3,897	3,221	4,468	3,045	17,530	10,435
2021	5,386	2,882	23,902	12,252	—	—	—	—	5,386	2,882	23,902	12,252
2022	4,143	2,497	22,277	10,353	3,028	1,833	9,030	6,366	7,171	4,330	31,307	16,719

(a) In computing total reserves on a barrels of oil equivalent (Boe) basis, gas is converted to oil based on its relative energy content at the rate of six Mcf of gas to one barrel of oil and NGLs are converted based upon volume; one barrel of natural gas liquids equals one barrel of oil.

In 2020, in West Texas we participated in the drilling of seven wells: one with Pioneer Natural Resources for 8.6% interest which was brought into production in July of 2020, and six wells with Apache on our Kashmir tract with an average 47.5% interest that were drilled but not completed at year-end and therefore classified as Proved Undeveloped in the year-end 2020 reserve report. The Company invested approximately $8.0 million in these seven wells in 2020. Also in 2020, reserves were added in West Texas through the addition of 11 horizontal wells completed in Midland County, Texas, in which we receive 0.56% to 1% over-riding royalty interest. In our Gulf Coast Region, in 2020, we successfully recompleted one operated well in the Segno field of Polk County, Texas with a 72.5% interest.

At December 31, 2020, in total, the Company had 3,221 Mboe of proved undeveloped reserves attributable to 13 wells operated by others, 10 of which were drilled but not completed by year-end 2020, and three that were not drilled until 2021. The three new horizontals along with the six uncompleted wells at year-end were brought online in late September and early October of 2021. These successful new wells are on our Kashmir tract in Upton County, Texas operated by Apache Corporation. These nine PUD wells at year-end 2020 accounted for 3,127 Mboe of the total undeveloped. The four other PUD wells, drilled but not completed at year-end 2020, are located in Grady County, Oklahoma, and accounted for 95 Mboe of the total undeveloped reserves.

In 2021, in West Texas, we participated with Apache in the drilling of three additional horizontals on the Kashmir Tract in Upton County, Texas and completed these three wells in September of 2021 along with six other wells drilled in 2020 on the same lease that were drilled but uncompleted at year-end. The Company has an average of 47.8% interest in these nine wells and invested approximately $30 million in these horizontal wells. Also in 2021, the Company participated with Ovintiv Mid-Continent for 11.25% interest in four two-mile horizontal wells in Canadian County, Oklahoma. Twelve of these thirteen horizontal wells were successfully completed and placed into production in the fourth quarter of 2021. One of the Ovintiv wells had a casing leak issue and has been temporarily abandoned. The Company invested approximately $32 million in these thirteen wells. In addition, in 2021, the Company added minor reserves through over-riding royalty interest in two wells drilling and completed in Grady County, Oklahoma.

At December 31, 2021, the Company had 159 Mboe of proved developed shut-in reserves attributable to three horizontals drilled and completed in Canadian County, Oklahoma, but not yet online at year-end. These reserves were converted to proved producing in the first quarter of 2022. At year-end 2021, we did not include proved undeveloped reserves in our reserve report because we had not yet received definitive drilling proposals from third-party operators for the more than fifteen horizontal wells that we planned to participate in located primarily in West Texas.

In 2022, the Company participated in eight horizontal wells that were drilled and completed; four located in Irion County, West Texas, operated by SEM Operating Company, in which we have 10.13% interest, and four located in Canadian County, Oklahoma, operated by Ovintiv Mid-Continent, Inc., in which we have an average 9% interest. Our investment in these eight wells was approximately $4 million and all were brought on production in August of 2022. In addition, the Company added reserves through 15 wells in which we have various minor over-riding royalty interest. Eight of these wells are located in West Texas and seven are located in Oklahoma.

In the fourth quarter of 2022, we began participation in the drilling of 20 horizontal wells located in West Texas operated by three different operators. In Martin County, we are participating with ConocoPhillips in five 2.5-mile-long horizontal wells in which the Company has 20.83% interest with a planned capital investment of $12.1 million. In Reagan County, we are participating with Hibernia Energy III in 10 two-mile horizontals with 25% interest and an expected investment of $25.6 million. Also in Reagan County, we are participating with Double Eagle (DE IV) in five two-mile-long horizontals with nearly 50% interest, carrying an expected net capital outlay of $23.4 million. All twenty of these West Texas wells are currently drilling or have been completed. All are expected to be online in the second quarter of 2023.

In January of 2023, the Company joined Ovintiv USA, Inc. in the spudding of three 3-mile-long horizontal wells in Canadian County, Oklahoma with 1.96% interest and an expected investment of $645,000. Production is expected to begin in May 2023. In addition, in March of 2023, Apache Corporation spud two 3-mile-long horizontals in Upton County, Texas in which the Company has 49.4% interest with an expected total capital investment of $16.1 million. We anticipate completion of these two 15,000' long horizontals in Upton County in May and production to occur in June of 2023.

At December 31, 2022, the Company had 6,366 Mboe of proved undeveloped reserves attributable to the 25 horizontal wells described above. In total, the Company expects to invest $78 million in these 25 horizontal wells, all of which are expected to be completed and online in the second quarter of 2023.

The estimated future net revenue (using current prices and costs as of those dates) and the present value of future net revenue (at a 10% discount for estimated timing of cash flow) for our proved developed and proved undeveloped oil and gas reserves at the end of each of the three years ended December 31, 2022, are summarized as follows (in thousands of dollars):

	Proved Developed		Proved Undeveloped		Total			
As of December 31,	**Future Net Revenue**	**Present Value 10 Of Future Net Revenue**	**Future Net Revenue**	**Present Value 10 Of Future Net Revenue**	**Future Net Revenue**	**Present Value 10 Of Future Net Revenue**	**Present Value 10 Of Future Income Taxes**	**Standardized Measure of Discounted Cash flow**
2020	$ 43,886	$ 34,717	$ 37,346	$ 21,823	$ 81,232	$ 56,539	$14,920	$ 41,619
2021	$275,227	$171,906	$ —	$ —	$275,227	$171,906	$36,100	$135,806
2022	$320,146	$192,688	$200,790	$118,081	$520,936	$310,769	$66,233	$244,536

The PV10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although this measure is not in accordance with U.S. generally accepted accounting principles ("GAAP"), we believe that the presentation of the PV10 Value is relevant and useful to investors because it presents the discounted future net cash flow attributable to proved reserves prior to taking into account corporate future income taxes and the current tax structure. We use this measure when assessing the potential return on investment related to oil and gas properties. The PV10 of future income taxes represents the sole reconciling item between this non-GAAP PV10 Value versus the GAAP measure presented in the standardized measure of discounted cash flow. A reconciliation of these values is presented in the last three columns of the table above. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to proved oil and natural gas reserves after income tax, discounted at 10%.

"Proved developed" oil and gas reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. "Proved undeveloped" oil and gas reserves are 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.

In accordance with U.S. generally accepted accounting principles, product prices are determined using the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, adjusted for oilfield or gas gathering hub and wellhead price differentials (e.g. grade, transportation, gravity, sulfur, and basic sediment and water) as appropriate. Also, in accordance with SEC specifications and U.S. generally accepted accounting principles, changes in market prices subsequent to December 31 are not considered.

While it may be reasonably anticipated that the prices received for the sale of our production may be higher or lower than the prices used in this evaluation, as described above, and the operating costs relating to such production may also increase or decrease from existing levels, such possible changes in prices and costs were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation for the SEC case. Actual volumes produced, prices received and costs incurred may vary significantly from the SEC case.

Natural gas prices, based on the twelve-month average of the first of the month Henry Hub index price, were $6.358 per MMBtu in 2022 as compared to $3.598 per MMBtu in 2021, and $1.985 per MMBtu in 2020. Oil prices, based on the West Texas Intermediate (WTI) Light Sweet Crude first of the month average spot price, were $93.67 per barrel in 2022 as compared to $66.56 per barrel in 2021, and $39.57 per barrel in 2020. Since January 1, 2022, we have not filed any estimates of our oil and gas reserves with, nor were any such estimates included in any reports to, any federal authority or agency, other than the Securities and Exchange Commission.

District Information

The following table represents certain reserves and well information as of December 31, 2022.

	Gulf Coast	Mid-Continent	West Texas	Other	Total
Proved Reserves as of December 31, 2022 (MBoe)					
Developed	790	2,549	7,001	13	10,353
Undeveloped	—	110	6,256	—	6,366
Total	790	2,659	13,257	13	16,719
Average Net Daily Production (Boe per day)	227	897	3,257	4	4,385
Gross Productive Wells (Working Interest and ORRI Wells)	150	508	557	151	1,373
Gross Productive Wells (Working Interest Only)	132	383	511	82	1,108
Net Productive Wells (Working Interest Only)	69	169	254	6	498
Gross Operated Productive Wells	89	176	310	—	575
Gross Operated Water Disposal, Injection and Supply wells	7	40	6	—	53

In several of our producing regions we have field service groups to service our operated wells and locations as well as third-party operators in the area. These services consist of well service support, site preparation and construction services for drilling and workover operations. Our operations are performed utilizing workover or swab rigs, water transport trucks, saltwater disposal facilities, various land excavating equipment and trucks we own and that are operated by our field employees.

Gulf Coast Region

Our development, exploitation, exploration and production activities in the Gulf Coast region are primarily concentrated in southeast Texas. This region is managed from our office in Houston, Texas. Principal producing intervals are in the Wilcox, San Miguel, Olmos, and Yegua formations at depths ranging from 3,000 to 12,500 feet. We had 150 producing wells (69 net) in the Gulf Coast region as of December 31, 2022, of which 89 wells are operated by us. Average net daily production in our Gulf Coast Region at year-end 2022 was 227 Boe. At December 31, 2022, we had 790 MBoe of proved reserves in the Gulf Coast region, which represented 4.7% of our total proved reserves. We maintain an acreage position of over 10,700 gross (3,215 net) acres in this region, primarily in Dimmit and Polk counties. We operate a field service group in this region from a field office in Carrizo Springs, Texas utilizing four workover rigs, twenty water transport trucks, two saltwater disposal wells and several trucks and excavating equipment. Services including well service support, site preparation and construction services for drilling and workover operations are provided to third-party operators as well as utilized in our own operated wells and locations. As of March 31, 2023, the Gulf Coast region has no operated wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

Mid-Continent Region

Our Mid-Continent activities are concentrated in central Oklahoma. This region is managed from our office in Oklahoma City, Oklahoma. As of December 31, 2022, we had 508 producing wells (169 net) in the

Mid-Continent area, of which 176 wells are operated by us. Principal producing intervals are in the Robberson, Avant, Skinner, Sycamore, Bromide, McLish, Hunton, Mississippian, Oswego, Red Fork, and Chester formations at depths ranging from 1,100 to 10,500 feet. Average net daily production in our Mid-Continent Region in 2022 was 897 Boe. At December 31, 2022, we had 2,659 MBoe of proved reserves in the Mid-Continent area, representing 16% of our total proved reserves. We maintain an acreage position of approximately 47,120 gross (10,297 net) acres in this region, primarily in Canadian, Kingfisher, Grant, Major, and Garvin counties. Our Mid-Continent region is actively participating with third-party operators in the horizontal development of lands that include Company owned interest in several counties in the Stack and Scoop plays of Oklahoma where drilling is primarily targeting reservoirs of the Mississippian, and Woodford formations.

As of March 31, 2023, in the Mid-Continent region, the Company is participating with 1.96% interest in the drilling of three 15,000' long horizontal wells in Canadian County, Oklahoma operated by Ovintiv Mid-Continent Inc. All three wells were spud in January and completions are expected in April of this year. These proved undeveloped drilling plans and their reserves are included in the 2022 year-end reserve report as proved undeveloped.

West Texas Region

Our West Texas activities are concentrated in the Permian Basin in Texas and New Mexico. The Spraberry field was discovered in 1949, encompasses eight counties in West Texas and the Company believes it is the largest oil field in the United States. The field is approximately 150 miles long and 75 miles wide at its widest point. The oil produced is West Texas Intermediate Sweet, and the gas produced is casing-head gas with an average energy content of 1,400 Btu. The oil and gas are produced primarily from five intervals; the Upper and Lower Spraberry, the Wolfcamp, the Strawn, and the Atoka, at depths ranging from 6,700 feet to 11,300 feet. This region is managed from our office in Midland, Texas. As of December 31, 2022, we had 557 wells (254 net) in the West Texas area, of which 310 wells are operated by us. Principal producing intervals are in the Spraberry, Wolfcamp, and San Andres formations at depths ranging from 4,200 to 12,500 feet. Average net daily production in Our West Texas Region at year end 2022 was 3,257 Boe. At December 31, 2022, we had 13,256 MBoe of proved reserves in the West Texas area, or 79.3 % of our total proved reserves. We maintain an acreage position of approximately 16,939 gross (9,969 net) acres in the Permian Basin in West Texas, primarily in Reagan, Upton, Martin and Midland counties and believe this acreage has significant resource potential for horizontal drilling in the Spraberry, Jo Mill, and Wolfcamp intervals. We operate a field service group in this region utilizing nine workover rigs, three hot oiler trucks, one kill truck and two roustabout trucks. Services, including well service support, site preparation and construction services for drilling and workover operations, are provided to third-party operators as well as utilized in our own operated wells and locations.

As of March 31, 2023, the Company was participating in the drilling of 15 two-mile-long horizontal wells in Reagan County, Texas with 49.7% interest in five wells operated by Double Eagle and 25% interest in ten wells operated by Hibernia Energy. In Upton County, Texas, the Company was also participating with Apache in the drilling of two 3-mile-long horizontals with 47.52% ownership. In Martin County, Texas, the Company is participating with ConocoPhillips in the drilling of five 2.5-mile-long horizontal with 20.83% interest. Combined, we expect to spend approximately $78 million in the drilling and completion of these 22 West Texas horizontals and their associated facilities. These 22 wells and their forecast reserves are included in the 2022 year-end reserve report as proved undeveloped. Additional development of each of these project areas is anticipated in the near future.

Item 3. LEGAL PROCEEDINGS.

None.

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 is listed and principally traded on the NASDAQ Stock Market under the ticker symbol "PNRG". The following table presents the high and low prices per share of our common stock during certain periods, as reported in the consolidated transaction reporting system.

	High	Low
2022		
First Quarter	$ 89.51	$66.61
Second Quarter	105.00	69.48
Third Quarter	100.00	75.23
Fourth Quarter	89.00	69.84
2021		
First Quarter	$ 98.00	$34.33
Second Quarter	53.72	39.89
Third Quarter	73.80	45.20
Fourth Quarter	71.71	58.50

The above quotations reflect inter-dealer prices, without retail mark-up, mark-down or commissions, and may not represent actual transactions.

As of April 10, 2023 there were 207 registered holders of the common stock.

Provisions of our line of credit agreement restrict our ability to pay dividends. Such dividends may be declared out of funds legally available therefore, when and as declared by our Board of Directors.

`**Issuer Purchases of Equity Securities**

There were no sales of equity securities by the Company during the period covered by this report. There was no purchase of equity securities by the Company during the period covered by this report.

2022 Month	Number of Shares	Average Price Paid per share	Maximum Number of Shares that May Yet Be Purchased Under The Program at Month—End(1)
January	2,981	$ 76.21	144,740
February	5,948	$ 73.26	138,792
March	2,259	$ 75.36	136,533
April	3,426	$ 74.82	133,107
May	5,963	$ 82.37	127,144
June	18,855	$ 85.18	108,289
July	15,645	$ 79.68	92,644
August	5,500	$ 87.99	87,144
September	800	$ 92.80	86,344
October	537	$ 74.07	85,807
November	15,263	$ 80.14	70,544
December	13,900	$ 82.56	56,644
Total/Average	91,077	$ 81.27	

(1) In December 1993, we announced that the Board of Directors authorized a stock repurchase program whereby we may purchase outstanding shares of the common stock from time-to-time, in open market transactions or negotiated sales. On October 31, 2012 and June 13, 2018, the Board of Directors of the Company approved an additional 500,000 and 200,000 shares respectively, of the Company's stock to be included in the stock repurchase program. A total of 3,700,000 shares have been authorized, to date, under this program. Through December 31, 2022, a total of 3,645,456 shares have been repurchased under this program for $82,481,928 at an average price of $ 22.63 per share. Additional purchases of shares may occur as market conditions warrant. We expect future purchases will be funded with internally generated cash flow or from working capital.

Item 6. SELECTED FINANCIAL DATA

We are a smaller reporting company and therefore no response is required pursuant to this Item.

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

The following discussion is intended to assist you in understanding our results of operations and our present financial condition. Our Consolidated Financial Statements and the accompanying Notes to the Consolidated Financial Statements included elsewhere in this Report contains additional information that should be referred to when reviewing this material. Our subsidiaries are listed in Note 1 to the Consolidated Financial Statements.

Overview:

We are an independent oil and natural gas company engaged in acquiring, developing, and producing oil and natural gas. We presently own producing and non-producing properties located primarily in Texas, and Oklahoma. In addition, we own a substantial amount of well servicing equipment. All of our oil and gas properties and interests are located in the United States. Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. We believe our balanced portfolio of assets and our ongoing hedging program position us well for both the current commodity price environment and future potential upside as we develop our attractive resource opportunities. Our primary sources of liquidity are cash generated from our operations and our credit facility.

We attempt to assume the position of operator in all acquisitions of producing properties and will continue to evaluate prospects for leasehold acquisitions and for exploration and development operations in areas in which we own interests. We continue to actively pursue the acquisition of producing properties. To diversify and broaden our asset base, we will consider acquiring the assets or stock in other entities and companies in the oil and gas business. Our main objective in making any such acquisitions will be to acquire income producing assets to build stockholder value through consistent growth in our oil and gas reserve base on a cost-efficient basis.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of any increases in oil and gas prices above the maximum fixed amount specified in the derivative agreements and subjects us to the credit risk of the counterparties to such agreements. Since all our derivative contracts are accounted for under mark-to-market accounting, we expect continued volatility in gains and losses on mark-to-market derivative contracts in our consolidated statement of operations as changes occur in the NYMEX price indices.

Market Conditions and Commodity Prices:

Our financial results depend on many factors, particularly the price of natural gas and crude oil and our ability to market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. In addition, our realized prices are further impacted by our derivative and hedging activities. We derive our revenue and cash flow principally from the sale of oil, natural gas and NGLs. As a result, our revenues are determined, to a large degree, by prevailing prices for crude oil, natural gas and NGLs. We sell our oil and natural gas on the open market at prevailing market prices or through forward delivery contracts. Because some of our operations are located outside major markets, we are directly impacted by regional prices regardless of Henry Hub, WTI or other major market pricing. The market price for oil, natural gas and NGLs is dictated by supply and demand; consequently, we cannot accurately predict or control the price we may receive for our oil, natural gas and NGLs. Index prices for oil, natural gas, and NGLs have improved since the lows of 2020 however we expect prices to remain volatile and consequently cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our capital program, production volumes or revenues.

Critical Accounting Estimates:

Proved Oil and Gas Reserves

Proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization. Proved reserves represent estimated quantities of natural gas, crude oil, condensate, and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease respectively. Depreciation, depletion and amortization of the cost of proved oil and gas properties are calculated using the unit-of-production method. The reserve base used to calculate depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. The reserve base includes only proved developed reserves for lease and well equipment costs, which include development costs and successful exploration drilling costs. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Asset Retirement Obligation (ARO):

The Company has significant obligations to remove tangible equipment and restore land at the end of oil and gas production operations. The Company's removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations. ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and gas properties. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value

Liquidity and Capital Resources:

Our primary sources of liquidity are cash generated from our operations, through our producing oil and gas properties, field services business and sales of acreage.

Net cash provided by operating activities for the year ended December 31, 2022 was $33.1 million, compared to $28.6 million in the prior year. Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices or changes in working capital accounts. Our oil and gas production will vary based on actual well performance but may be curtailed due to factors beyond our control.

Our realized oil and gas prices vary due to world political events, supply and demand of products, product storage levels, and weather patterns. We sell the majority of our production at spot market prices. Accordingly, product price volatility will affect our cash flow from operations. To mitigate price volatility, we sometimes lock in prices for some portion of our production through the use of derivatives.

If our exploratory drilling results in significant new discoveries, we will have to expend additional capital to finance the completion, development, and potential additional opportunities generated by our success. We believe that, because of the additional reserves resulting from the successful wells and our record of reserve growth in recent years, we will be able to access sufficient additional capital through bank financing.

Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. For 2023, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our 2023 capital budget is reflective of commodity prices and has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility. As we have done historically to preserve or enhance liquidity, we may adjust our capital program throughout the year, divest assets, or enter into strategic joint ventures.

The Company maintains a Credit Agreement with a maturity date of June 1, 2026, providing for a credit facility totaling $300 million, with a borrowing base of $60 million. As of March 31, 2023, the Company has no outstanding borrowings and $60 million in availability under this facility. The bank reviews the borrowing base semi-annually and, at their discretion, may decrease or propose an increase to the borrowing base relative to a re-determined estimate of proved oil and gas reserves. The next borrowing base review is scheduled for May 2023. Our oil and gas properties are pledged as collateral for the line of credit and we are subject to certain financial and operational covenants defined in the agreement. We are currently in compliance with these covenants and expect to be in compliance over the next twelve months. If we do not comply with these covenants on a continuing basis, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable. Our borrowing base may decrease as a result of lower natural gas or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for other reasons set forth in our revolving credit agreement. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, our ability to borrow under our revolving credit facility may be limited and we could be required to repay any indebtedness in excess of the re-determined borrowing base.

Our credit agreement required us to hedge a portion of our production as forecasted for the PDP reserves included in our borrowing base review engineering reports. Accordingly, the Company has in place the following swap agreements for oil and natural gas.

	2023	2023
Swap Agreements		
Natural Gas (MMBTU)	377,000	$ 3.87
Oil (barrels)	114,200	$74.07

The Company's activities include development and exploratory drilling. Our strategy is to develop a balanced portfolio of drilling prospects that includes lower risk wells with a high probability of success and higher risk wells with greater economic potential. Horizontal development of our resource base provides superior returns relative to vertical development due to the ability of each horizontal wellbore to come in contact with a greater volume of reservoir rock across a greater distance, more efficiently draining the reserves with less infrastructure and thus at a lower cost per acre.

In 2022 the Company participated with SEM Operating Company, LLC in four horizontal wells in Irion County, Texas with 10.3% interest for approximately $2.35 million and with Ovintiv Mid-Continent, Inc. in four horizontal wells in Canadian County with an average of 9% interest for $1.77 million. All eight wells were put into production in August of 2022.

In the fourth quarter of 2022, we began participation in the drilling of 20 horizontal wells located in West Texas operated by three different operators. In Martin County, we are participating with ConocoPhillips in five 2.5-mile-long horizontal wells in which the Company has 20.83% interest with a planned capital expense of $12.1 million. In Reagan County we are participating with Hibernia Energy III in 10 two-mile horizontals with 25% interest and an expected investment of $25.6 million. Also in Reagan County, we are participating with Double Eagle (DE IV) in five two-mile-long horizontals with nearly 50% interest, carrying an expected net capital outlay of $23.4 million. All twenty of these West Texas wells are currently drilling or have been completed. All are expected to be on line in the second quarter of 2023.

In January of 2023, the Company joined Ovintiv USA, Inc. in the spudding of three 3-mile-long horizontal wells in Canadian County, Oklahoma with 1.96% interest and an expected investment of $645,000. Production is expected to begin in May, 2023. In addition, in March of 2023, Apache Corporation has spud two 3-mile-long horizontals in Upton County, Texas in which the Company has 49.4% interest with an expected total capital investment of $16,1 million. We anticipate completion of these two 15,000' long horizontals in Upton County in May and production to occur in June of 2023.

In total, the Company expects to invest $78 million dollars in these 25 horizontal wells. We prepaid drilling costs of $32 million in December of 2022 and the remaining $46 million estimated drilling and completion expenditures will occur in 2023. All 25 wells are expected to be completed and on-line in the second quarter of 2023.

We anticipate that success from the 22 horizontals in West Texas described above will lead to additional near-term horizontal drilling covering five leasehold blocks in three counties of West Texas: 29 additional 10,000' long horizontals in Reagan County with Hibernia, Double Eagle and BTA Oil Producers, ten additional 12,500' long horizontals in Martin County with ConocoPhillips, and six additional 15,000' long horizontals in Upton County with Apache. These anticipated additional 42 drilling proposals will target various proven pay intervals of the Wolfcamp and Spraberry formations and will require an estimated $200 million in net capital investment. In addition, we have more than 200 drilling locations that could potentially be developed.

In West Texas the Company maintains an acreage position of 16,940 gross (9,969 net) acres, primarily in Reagan, Upton, Martin, and Midland counties where our horizontal activity is focused. We believe this acreage has significant resource potential in as many as 10 reservoirs, including benches of the Spraberry, Jo Mill, and Wolfcamp that support the potential drilling of as many as 200 additional horizontal wells.

In Oklahoma, the Company's horizontal activity is primarily focused in Canadian, Grady, Kingfisher, Garfield, Major, and Garvin counties where we have approximately 4,113 net leasehold acres in the Scoop/Stack Play. Of this acreage we believe 2,355 net acres holds significant additional resource potential that could support the drilling of as many as 46 new horizontal wells based on an estimate of four wells per multi-section drilling unit, two in the Mississippian and two in the Woodford Shale. In the near term, we anticipate nine new drilling proposals to be received with an estimated net expense of $5.2 million covering 338 net leasehold acres. Proposals may be received on the remaining 2,017 acres, however, rather than participate we may choose to sell the acreage or farm-out receiving cash and retaining an over-riding royalty interest.

During 2022, to supplement cash flow and finance our future drilling programs, the Company entered into an agreement with Double Eagle to create a 2,560-acre AMI for the joint development of horizontal wells; as part of this agreement, the Company sold a portion of its interest in this acreage for proceeds of $16.1 million. In addition, in 2022, we sold 240 net acres in Reagan County to BTA Oil Producers for proceeds of $1.8 million, and we sold 353 net acres in Canadian County, Oklahoma to Paloma Partners, IV, Inc. for $1.3 million. Through three other transactions, we divested a minor tract in Lea County, NM for a nominal cash consideration and assigned nine wellbores in West Texas to a third-party operator in exchange for a reduction in our future plugging liability. In this same year, the Company acquired 3.2 net mineral acres in Upton County, Texas for $16,000.

These sales along with our cash flow have allowed the Company to eliminate its bank debt as of March 31, 2023, with the right to borrow up to $60 million under its current revolving line of credit.

The majority of our capital spending is discretionary, and the ultimate level of expenditures will be dependent on our assessment of the oil and gas business environment, the number and quality of oil and gas prospects available, the market for oilfield services, and oil and gas business opportunities in general.

The Company has a stock repurchase program in place, spending under this program in 2022 and 2021 was $7.4 million and $145 thousand, respectively. The Company expects continued spending under the stock repurchase program in 2023.

Results of Operations:

2022 and 2021 Compared

We reported a net income of $48.7 million for 2022, or $24.91 per share, compared to $2.1 million, or $1.05 per share for 2021. The current year net income reflects production and commodity price increases, partially offset by losses related to derivative instruments. The significant components of income and expense are discussed below.

Oil, NGL and gas sales increased $51.1 million, or 69.7% to $124.1 million for the year ended December 31, 2022 from $73.1 million for the year ended December 31, 2021. Crude oil, NGL and natural gas sales vary due to changes in volumes of production sold and realized commodity prices. Our realized prices at the well head increased an average of $28.31 per barrel, or 41.40% on crude oil, increased an average of $8.73 per barrel, or 32.37% on NGL and increased $2.01 per Mcf, or 57.00% on natural gas during 2022 as compared to 2021.

Our crude oil production increased by 201,000 barrels, or 27.24% to 939,000 barrels for the year ended December 31, 2022 from 738,000 barrels for the year ended December 31, 2021. Our NGL production increased by 1,000 or 0.24% to 417,000 for the year ended December 31, 2022 from 416,000 barrels for the year ended

December 31, 2021. Our natural gas production increased by 89 MMcf, or 2.75% to 3,325 MMcf for the year ended December 31, 2022 from 3,236 MMcf for the year ended December 31, 2021. The changes in crude oil, NGL and natural gas production volumes are a result of new wells placed in production offset by the natural decline of existing properties.

The following table summarizes the primary components of production volumes and average sales prices realized for the years ended December 31, 2022 and 2021 (excluding realized gains and losses from derivatives).

	Years ended December 31,			
	2022	2021	Increase / (Decrease)	Increase / (Decrease)
Barrels of Oil Produced	939,000	738,000	201,000	27.24%
Average Price Received	$ 96.70	$ 68.39	$ 28.31	41.40%
Oil Revenue (In 000's)	$ 90,803	$ 50,474	$ 40,329	79.90%
Mcf of Gas Sold	3,325,000	3,236,000	89,000	2.75%
Average Price Received	$ 5.54	$ 3.53	$ 2.01	57.00%
Gas Revenue (In 000's)	$ 18,428	$ 11,432	$ 6,996	1.20%
Barrels of Natural Gas Liquids Sold	417,000	416,000	1,000	0.24%
Average Price Received	$ 35.70	$ 26.97	$ 8.73	32.37%
Natural Gas Liquids Revenue (In 000's)	$ 14,887	$ 11,220	$ 3,667	32.68%
Total Oil & Gas Revenue (In 000's)	$ 124,118	$ 73,126	$ 50,992	69.73%

Oil, Natural Gas and NGL Derivatives We do not apply hedge accounting to any of our commodity based derivatives, thus changes in the fair market value of commodity contracts held at the end of a reported period, referred to as mark-to-market adjustments, are recognized as unrealized gains and losses in the accompanying condensed consolidated statements of operations. As oil and natural gas prices remain volatile, mark-to-market accounting treatment creates volatility in our revenues.

The following table summarizes the results of our derivative instruments for the years ended December 2022 and 2021:

	Years ended December 31,	
	2022	2021
Oil derivatives – realized gains (losses)	$(12,101)	$(3,212)
Oil derivatives – unrealized (losses) gains	3,713	(4,055)
Total (losses) gains on oil derivatives	$ (8,388)	$(7,267)
Natural gas derivatives – realized (losses) gains	(4,543)	(1,833)
Natural gas derivatives – unrealized gains (losses)	892	(859)
Total (losses) gains on natural gas derivatives	$ (3,651)	$(2,692)
Total (losses) gains on oil and natural gas	$(12,039)	$(9,959)

Prices received for the years ended December 31, 2022 and 2021, respectively, including the impact of derivatives were:

	2022	2021	Increase / (Decrease)	Increase / (Decrease)
Oil Price	$87.77	$64.04	$23.73	37.05%
Gas Price	$ 4.44	$ 2.97	$ 1.47	49.64%
NGL Price	$35.70	$26.97	$ 8.73	32.37%

Field service expense increased $1.9 million, or 20.7% to $11.1 million for the year ended December 31, 2022 from $9.2 million for the year ended December 31, 2021. Field service expenses primarily consist of wages and vehicle operating expenses which have increased during 2022 related to increased utilization of our equipment services.

Depreciation, depletion, amortization and accretion on discounted liabilities increased $1.8 million, or 6.8% to $28.1 million for the year ended December 31, 2022 from $26.3 million for the year ended December 31, 2021. The DD&A expense is primarily attributable to our properties in West Texas and Oklahoma, reflecting the addition of new properties offset by the declining cost basis of existing properties.

General and administrative expense increased $11.1 million, or 122.0% to $20.2 million for the year ended December 31, 2022 from $9.1 million for the year ended December 31, 2021. This increase in 2022 is primarily due to increased employee count, compensation and benefits

Gain on sale and exchange of assets of $31.8 million for the year ended December 31, 2022 and $1.5 million for the year ended December 31, 2021 consists principally of sales of deep rights in undeveloped acreage in West Texas.

Interest expense decreased $1.1 million, or 55.0% to $0.9 million for the year ended December 31, 2022 from $2.0 million for the year ended December 31, 2021. This decrease reflects the reduced borrowings under our revolving credit agreement offset by an increase in rates.

Tax expense of $10.3 million and $2.5 million were recorded for the years ended December 31, 2022 and 2021, respectively. The change in our income tax provision was primarily due to the increase in pre-tax income for the year ended December 31, 2022.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are a smaller reporting company and therefore no response is required pursuant to this Item.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The consolidated financial statements and supplementary information included in this Report are described in the Index to Consolidated Financial Statements at Page F-1 of this Report.

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

None.

Item 9A. CONTROLS AND PROCEDURES.

As of the end of the period covered by this Annual Report on Form 10-K, our principal executive officer and principal financial officer have evaluated the effectiveness of our "disclosure controls and procedures" ("Disclosure Controls"). Disclosure Controls, as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), are procedures that are designed with the objective of ensuring that information required to be disclosed in our reports filed under the Exchange Act, such as this Annual Report, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Disclosure Controls are also designed with the objective of ensuring that such information is accumulated and communicated to our management, including the chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Our management, including the chief executive officer and chief financial officer, does not expect that our Disclosure Controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

Members of our management, including our chief executive officer and chief financial officer, have evaluated the effectiveness of our disclosure controls and procedures, as defined by paragraph (e) of Exchange Act Rules 13a-15 or 15d-15, as of December 31, 2022 the end of the period covered by this Report. Based upon that evaluation, these officers concluded that our disclosure controls and procedures were effective as of December 31, 2022.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance that assets are safeguarded against loss from unauthorized use or disposition, transactions are executed in accordance with appropriate management authorization and accounting records are reliable for the preparation of financial statements in accordance with U.S. 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 the policies or procedures may deteriorate.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2022. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control – Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of our Board of Directors.

Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2022.

This Annual Report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.

There have been no changes in our internal controls over financial reporting during the fourth fiscal quarter ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. OTHER INFORMATION.

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information relating to the Company's Directors, nominees for Directors and executive officers will be included in the Company's definitive proxy statement relating the Company's Annual Meeting of Stockholders to be held in June 7, 2023, and which is incorporated herein by reference.

Item 11. EXECUTIVE COMPENSATION.

Information relating to executive compensation will be included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June 7, 2023, and which is incorporated herein by reference.

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

Information relating to security ownership of certain beneficial owners and management will be included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June 7, 2023, and which is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Information relating to certain transactions by Directors and executive officers of the Company will be included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June 7, 2023, and which is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

Information relating to principal accountant fees and services will be included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June 7, 2023, and which is incorporated herein by reference.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as part of this Report:

1. Financial statements (Index to Consolidated Financial Statements at page F-1 of this Report)
2. Financial Statement Schedules (Index to Consolidated Financial Statements – Supplementary Information at page F-1 of this Report)
3. Exhibits:

3.1	Certificate of Incorporation of PrimeEnergy Resources Corporation, as amended and restated of December 21, 2018, (filed as Exhibit 3.1 of PrimeEnergy Resources Corporation Form 8-K on December 27, 2018, and incorporated herein by reference).
3.2	Bylaws of PrimeEnergy Resources Corporation as amended and restated as of April 24, 2020 (filed as Exhibit 3.2 of PrimeEnergy Resources Corporation Form 8-K on April 27, 2020 and incorporated herein by reference).
10.18	Composite copy of Non-Statutory Option Agreements (Incorporated by reference to Exhibit 10.18 of PrimeEnergy Resources Corporation Form 10-K for the year ended December 31, 2004).
10.22.6	FOURTH AMENDED AND RESTATED CREDIT AGREEMENT dated as of July 5, 2022, is among PRIMEENERGY RESOURCES CORPORATION, a Delaware corporation (the “Borrower”), each of the Lenders from time to time party hereto and CITIBANK, N.A. (in its individual capacity, “Citibank”), as administrative agent for the Lenders (in such capacity, together with its successors in such capacity, the “Administrative Agent”) (filed as exhibit 10.22.6 of PrimeEnergy Resources Corporation Form 10-Q for the Quarter Ended June 30 2022, and incorporated by reference).
10.22.6.1	FIRST AMENDMENT TO FOURTH AMENDED AND RESTATED CREDIT AGREEMENT, dated as of October 31, 2022 (the “First Amendment Effective Date”), is among PRIMEENERGY RESOURCES CORPORATION, a Delaware corporation (the “Borrower”), CITIBANK, N.A., as administrative agent (in such capacity, the “Administrative Agent”) and as Issuing Bank, each Guarantor party hereto and the financial institutions party hereto as Lenders (filed herewith).
14	PrimeEnergy Resources Corporation Code of Business Conduct and Ethics, as amended December 16, 2011 (Incorporated by reference to Exhibit 14 of PrimeEnergy Resources Corporation Form 10-K for the year ended December 31, 2011).
21	Subsidiaries (filed herewith).
23	Consent of Ryder Scott Company, L.P. (filed herewith).
31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).
31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Summary Reserve Report dated March 7, 2023, of Ryder Scott Company, L.P. (filed herewith).
101.INS	Inline XBRL (eXtensible Business Reporting Language) Instance Document (filed herewith)

101.SCH	Inline XBRL Taxonomy Extension Schema Document (filed herewith)
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document (filed herewith)
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document (filed herewith)
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document (filed herewith)
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document (filed herewith)
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

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, on the **17**th day of April, 2023.

PrimeEnergy Resources Corporation

By: /s/ Charles E. Drimal, Jr.
Charles E. Drimal, Jr.
Chairman, Chief Executive Officer and President

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 indicated and on the 17th, day of April, 2023.

/s/ Charles E. Drimal, Jr. Charles E. Drimal, Jr.	Chairman, Chief Executive Officer and President; The Principal Executive Officer
/s/ Beverly A. Cummings Beverly A. Cummings	Director, Executive Vice President and Treasurer; The Principal Financial Officer
/s/ Clint Hurt Clint Hurt	Director
/s/ Thomas S. T. Gimbel Thomas S. T. Gimbel	Director
/s/ H. Gifford Fong H. Gifford Fong	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
PrimeEnergy Resources Corporation and Subsidiaries:

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PrimeEnergy Resources Corporation and Subsidiaries (the “Company”) as of December 31, 2022 and 2021, the related consolidated statements of income, equity, and cash flows for each of the years then ended, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the years then ended, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Depreciation, Depletion and Amortization and Impairment of Property and Equipment

Description of the Matter

At December 31, 2022, the carrying value of the Company's property and equipment was $174.0 million, and depreciation, depletion and amortization (DD&A) expense was $28.1 million for the year then ended. As described in Note 1, the Company follows the "successful efforts" method of accounting for its oil and gas properties. Under the "successful efforts" method, costs of acquiring undeveloped oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs, are capitalized. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations. Annual lease rentals and exploration expenses, including geological and geophysical expenses and exploratory dry hole costs, are charged against income as incurred. Costs of drilling and equipping productive wells, including development of dry holes and related production facilities, are capitalized. All other property and equipment are carried at cost. Depreciation and depletion of oil and gas production equipment and properties are determined under the unit-of-production method based on estimated proved developed recoverable oil and gas reserves. Depreciation of all other equipment is determined under the straight-line method using various rates based on useful lives generally ranging from 5 to 10 years. The cost of assets and related accumulated depreciation is removed from the accounts when such assets are disposed of, and any related gains or losses are reflected in current earnings.

Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated and successful.

The Company reviews long-lived assets, including oil and gas properties, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted cash flows, the assets are impaired, and an impairment loss is recorded. The amount of impairment is based on the estimated fair value of the assets determined by discounting anticipated future net cash flows.

Proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization. Proved reserves represent estimated quantities of natural gas, crude oil, condensate, and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time.

Estimates of oil and gas reserves, as determined by independent petroleum engineers, are continually subject to revision based on price, production history and other factors. Depletion expense, which is computed based on the units of production method, could be significantly impacted by changes in such estimates. Additionally, U.S. generally accepted accounting principles require that if the expected future undiscounted cash flows from an asset are less than its carrying cost, that asset must be written down to its fair market value. As the fair market value of an oil and gas property will usually be significantly less than the total undiscounted future net revenues expected from that asset, slight changes in the estimates used to determine future net revenues from an asset could lead to the necessity of recording a significant impairment of that asset.

Auditing the Company's DD&A and impairment calculations is complex because of the use of independent petroleum engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating oil and gas reserves.

How We Addressed the Matter in Our Audit

We obtained an understanding and evaluated the design of the Company's controls over its process to calculate DD&A and impairment, including management's controls over the completeness and accuracy of the financial data utilized by the engineers in estimating oil and gas reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's independent petroleum engineers responsible for the preparation of the proved oil and gas reserve estimates for select properties. We also utilized the services of an independent auditor-engaged specialist to ensure the methodologies and assumptions utilized by the Company's independent engineers were reasonable and in accordance with industry standards. In addition, we compared the Company's recent production with its reserve estimates for properties that have significant production or significant reserve quantities and inquired of disproportionate ratios that did not align with our expectations. We also tested the mathematical accuracy of the DD&A and impairment calculations, including comparing the oil and gas reserve amounts used in the calculations to the Company's reserve reports.

Accounting for Asset Retirement Obligations

Description of the Matter

At December 31, 2022, the asset retirement obligation (ARO) balance totaled $15.4 million. As further described in Note 1, the Company's ARO primarily represents the estimated present value of the amount the Company will incur to plug, abandon, and remediate producing properties at the end of their productive lives, in accordance with applicable state laws. The Company determined its asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The asset retirement obligation is recorded as a liability at its estimated present value at its inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the statements of income.

The Company's liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive life of wells and a risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of the Company's wells, the costs to ultimately retire the wells may vary significantly from previous estimates.

Auditing the Company's ARO is complex and highly judgmental because of the significant estimation by management in determining the obligation. In particular,

	the estimate was sensitive to significant subjective assumptions such as retirement cost estimates and the estimated timing of settlements, which are both affected by expectations about future market and economic conditions.
How We Addressed the Matter in Our Audit	We obtained an understanding and evaluated the design of the Company's internal controls over its ARO estimation process, including management's review of the significant assumptions that have a material effect on the determination of the obligations. Based on our evaluation, we designed our audit procedures to include, among others, assessing the significant assumptions and inputs used in the valuation, such as retirement cost estimates and timing of settlement assumptions. Additionally, we compared the ARO against historical results, reviewed the reasonableness of the discount rate utilized in the estimate, considered the reasonableness of the current and long-term portion of the obligation by comparing the accretion expense trends, and considered the completeness of the properties included in the estimate by comparing to the Company's reserve reports.

/s/ GRASSI & CO., CPAs, P.C.

We have served as the Company's auditor since 1989.

New York, New York
April 17, 2023

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Thousands of dollars, except share data)

	As of December 31, 2022	As of December 31, 2021
ASSETS		
Current Assets		
Cash and cash equivalents	$ 26,543	$ 10,347
Accounts receivable, net	12,147	14,208
Prepaid obligations	32,839	733
Due from related parties	388	—
Derivative asset short-term	210	—
Other current assets	38	40
Total Current Assets	72,165	25,328
Property and Equipment		
Oil and gas properties at cost	555,280	539,484
Less: Accumulated depletion and depreciation	(385,811)	(359,742)
	169,469	179,742
Field and office equipment at cost	27,246	27,080
Less: Accumulated depreciation	(22,728)	(22,159)
	4,518	4,921
Total Property and Equipment, Net	173,987	184,663
Other assets	985	923
Total Assets	$ 247,137	$ 210,914
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 11,451	$ 7,282
Accrued liabilities	25,750	7,821
Due to related parties	—	52
Current portion of asset retirement and other long-term obligations	2,566	1,630
Derivative liability short-term	1,190	4,935
	40,957	21,720
Long-Term Bank Debt	11,000	36,000
Asset Retirement Obligations	13,525	13,222
Derivative Liability Long-Term	—	650
Deferred Income Taxes	39,968	38,743
Other Long-Term Obligations	1,334	1,488
Total Liabilities	106,784	111,823
Commitments and Contingencies		
Equity		
Common stock, $.10 par value; 2022 and 2021: Authorized: 2,810,000 shares, outstanding 2022: 1,901,000 shares; outstanding 2021: 1,992,077 shares.	281	281
Paid-in capital	7,555	7,555
Retained earnings	177,566	128,902
Treasury stock, at cost; 2022: 909,000 shares; 2021: 817,923	(45,049)	(37,647)
Total Stockholders' Equity	140,353	99,091
Total Liabilities and Equity	$ 247,137	$ 210,914

The accompanying Notes are an integral part of these Consolidated Financial Statements

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

(Thousands of dollars, except per share amounts)

	For the Years Ended December 31, 2022	2021
Revenues		
Oil sales	$ 90,803	$50,474
Natural gas sales	18,428	11,432
Natural gas liquids sales	14,887	11,220
Realized gain (loss) on derivative instruments, net	(16,644)	(5,045)
Field service income	12,978	9,262
Unrealized (loss) on derivative instruments	4,605	(4,914)
Other income	30	29
Total Revenues	125,087	72,458
Costs and Expenses		
Lease operating expense	37,816	24,419
Field service expense	11,094	9,152
Depreciation, depletion, amortization and accretion on discounted liabilities	28,068	26,325
General and administrative expense	20,233	9,084
Total Costs and Expenses	97,211	68,980
Gain on Sale and Exchange of Assets	31,789	1,478
Income from Operations	59,665	4,956
Other Income and Expenses		
Less: Interest expense	(909)	(2,007)
Add: Interest income	237	—
Add: PPP Loan Forgiveness	—	1,693
Income Before Provision Income Taxes	58,993	4,642
Income Tax Expense	10,329	2,516
Net Income	48,664	2,126
Less: Net Income Attributable to Non-Controlling Interest	—	28
Net Income Attributable to PrimeEnergy	$ 48,664	$ 2,098
Basic Income Per Common Share	$ 24.91	$ 1.05
Diluted Income Per Common Share	$ 17.95	$ 0.76

The accompanying Notes are an integral part of these Consolidated Financial Statements

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(Thousands of dollars, except share amounts)

	Shares Outstanding	Common Stock	Additional Paid-In Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity – PrimeEnergy	Non-Controlling Interest	Total Equity
Balance at December 31, 2020	1,994,177	$281	$7,541	$126,804	$(37,502)	$ 97,124	$ 874	$ 97,998
Purchase 2,100 shares of common stock	(2,100)	—	—	—	(145)	(145)	—	(145)
Net Income	—	—	—	2,098	—	2,098	28	2,126
Purchase of non-controlling interest	—	—	14	—	—	14	(58)	(44)
Distributions to non-controlling interest	—	—	—	—	—	—	(844)	(844)
Balance at December 31, 2021	1,992,077	$281	$7,555	$128,902	$(37,647)	$ 99,091	$ —	$ 99,091
Purchase 91,077 shares of common stock	(91,077)	—	—	—	(7,402)	(7,402)	—	(7,402)
Net Income	—	—	—	48,664	—	48,664	—	48,664
Balance at December 31, 2022	1,901,000	$281	$7,555	$177,566	$(45,049)	$140,353	$ —	$140,353

The accompanying Notes are an integral part of these Consolidated Financial Statements

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of dollars)

	For the Years Ended December 31, 2022	2021
Cash Flows from Operating Activities:		
Net Income	$ 48,664	$ 2,126
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion on discounted liabilities	28,068	26,325
Gain on sale of properties	(31,789)	(1,478)
Unrealized (gain) loss on derivative instruments	(4,605)	4,914
PPP Loan forgiveness	—	(1,693)
Provision for deferred income taxes	1,225	2,376
Changes in assets and liabilities:		
Accounts receivable	2,096	(6,760)
Allowance for doubtful accounts	(35)	(227)
Due from related parties	(388)	44
Due to related parties	(52)	(30)
Prepaid obligations	(32,106)	(143)
Other current assets	2	64
Accounts payable	4,169	2,065
Accrued liabilities	17,929	1,034
Other assets	100	—
Other long-term liabilities	(151)	—
Net Cash Provided by Operating Activities	33,127	28,617
Cash Flows from Investing Activities:		
Capital expenditures, including exploration expense	(15,974)	(20,726)
Proceeds from sale of properties and equipment	31,445	1,478
Net Cash Provided by (Used in) Investing Activities	15,471	(19,248)
Cash Flows from Financing Activities:		
Purchase of stock for treasury	(7,402)	(145)
Purchase of non-controlling interests	—	(676)
Increase in long-term bank debt and other long-term obligations	11,000	11,209
Repayment of long-term bank debt and other long-term obligations	(36,000)	(10,209)
Distribution to non-controlling interest	—	(197)
Net Cash Used in Financing Activities	(32,402)	(18)
Net Increase in Cash and Cash Equivalents	16,196	9,351
Cash and Cash Equivalents at the Beginning of the Year	10,347	996
Cash and Cash Equivalents at the End of the Year	$ 26,543	$ 10,347
Supplemental Disclosures:		
Income taxes paid during the year	$ 539	$ 343
Interest paid during the year	$ 842	$ 1,957
Non-Cash Disclosures:		
Purchase of non-controlling interest	$ —	$ 14
Distribution of non-controlling interest in liquidated partnerships	$ —	$ 647

The accompanying Notes are an integral part of these Consolidated Financial Statements

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Operations and Significant Accounting Policies

Nature of Operations:

PrimeEnergy Resources Corporation ("PERC"), a Delaware corporation, was organized in March 1973 and is engaged in the development, acquisition and production of oil and natural gas properties. PrimeEnergy Resources Corporation and its subsidiaries are herein referred to as the "Company." The Company owns leasehold, mineral and royalty interests in producing and non-producing oil and gas properties across the United States, primarily in Oklahoma, and Texas. The Company operates approximately 630 active wells and owns non-operating interests and royalties in approximately 800 additional wells. Additionally, the Company provides well-servicing support operations, site-preparation and construction services for oil and gas drilling and reworking operations, both in connection with the Company's activities and providing contract services for third parties. The Company is publicly traded on the NASDAQ under the symbol "PNRG." PERC owns Eastern Oil Well Service Company ("EOWSC") and EOWS Midland Company ("EMID") which perform oil and gas field servicing. PERC also owns Prime Operating Company ("POC"), which serves as operator for most of the producing oil and gas properties owned by the Company and affiliated entities. The markets for the Company's products are highly competitive, as oil and gas are commodity products and prices depend upon numerous factors beyond the control of the Company, such as economic, political and regulatory developments and competition from alternative energy sources.

Consolidation and Presentation:

The consolidated financial statements include the accounts of PrimeEnergy Resources Corporation, its subsidiaries and the Partnerships, using the full consolidation method for those partnerships which are controlled by the Company. The Company's reserve estimates are based on the full consolidation method. DD&A expense and evaluation of impairment may differ from the Partnership as the Company's cost basis for the Partnership interests acquired may be different than the cost basis at the Partnership level for properties acquired by the Partnership. All significant intercompany balances and transactions are eliminated in preparing the consolidated financial statements.

Reclassifications:

Certain reclassifications have been made to prior year statements to conform with the current year presentation. These reclassifications have no impact on net income and no material impact on any other financial statement captions.

Subsequent Events:

Subsequent events have been evaluated through the date that the consolidated financial statements were issued. During this period, there were no material subsequent items requiring disclosure, other than as stated in Footnote 4, to these consolidated financial statements.

Use of Estimates:

The preparation of consolidated financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Estimates of oil and gas reserves, as determined by independent petroleum engineers, are continually subject to revision based on price, production history and other factors. Depletion expense, which is computed based on the units of production method, could be significantly impacted by changes in such estimates. Additionally, U.S. generally accepted accounting principles require that if the expected future undiscounted cash flows from an asset are less than its carrying cost, that asset must be written down to its fair market value. As the fair market value of an oil and gas property will usually be significantly less than the total undiscounted future net revenues expected from that asset, slight changes in the estimates used to determine future net revenues from an asset could lead to the necessity of recording a significant impairment of that asset.

Oil and gas properties:

The Company utilizes the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized while nonproductive exploration costs and geological and geophysical expenditures are expensed. Oil and gas leasehold acquisition costs are capitalized when incurred and included as unproved oil and gas properties in the consolidated balance sheets. The Company does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met: (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The Company’s exploratory wells include extension wells that extend the limits of a known reservoir. Due to the capital intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination on its commercial viability. In these instances, the project’s feasibility is not contingent upon price improvements or advances in technology, but rather the Company’s ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies’ production data in the area, transportation or processing facilities, and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company’s assessment of suspended exploratory/extension well costs is continuous until a decision can be made that the project has found sufficient proved reserves to sanction the project or is determined to be noncommercial and is charged to exploration and abandonments expense. As of December 31, 2022, the Company had no such suspended well costs.

The capitalized costs of proved properties are depleted using the unit-of-production method based on proved reserves. Costs of significant nonproducing properties, wells in the process of being drilled and in-process development projects are excluded from depletion until the related project is completed and proved reserves are established or, if unsuccessful, abandonments expense is recognized. Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion, depreciation and amortization, if doing so does not materially impact the depletion rate of its amortization base. Generally, no gain or loss is recorded until an entire amortization base is sold. However, gain or loss is recorded from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

Field and office Equipment:

Depreciation of all other equipment is determined under the straight-line method using various rates based on useful lives generally ranging from 5 to 10 years. The cost of assets and related accumulated depreciation is removed from the accounts when such assets are disposed of, and any related gains or losses are reflected in current earnings.

Capitalization of Interest:

Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated and successful.

Impairment of Long-Lived Assets:

The Company reviews long-lived assets, including oil and gas properties, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted cash flows, the assets are impaired, and an impairment loss is recorded. The amount of impairment is based on the estimated fair value of the assets determined by discounting anticipated future net cash flows.

Fair Value:

The Company follows the authoritative guidance that establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by U.S. generally accepted accounting principles to be measured at fair value. The guidance defines fair value 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 (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. The guidance establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable; hence, these valuations have the lowest priority.

Revenue recognition:

The majority of the Company’s production is operated by third party operators where we elect to market our products under the joint operating agreements. Accordingly, we receive our proportionate share of revenue proceeds for production sold by the operator under the operator’s marketing agreements. The Company recognizes revenue and any costs indicated by the operator in the related production period.

The Company recognizes revenue related to production from properties operated by the Company when control of the promised goods or services is transferred to customers at an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

Oil sales. The Company recognizes oil sales revenue when (i) control/custody transfers to the purchaser and (ii) the agreed-upon index price, net of any price differentials, is fixed and determinable. Any costs incurred prior to the transfer of control to the customer, such as gathering and transportation costs, are recognized as oil and gas production costs.

NGL and gas sales. Under the majority of the Company’s gas processing contracts, gas is delivered to a midstream processing entity and the Company recognizes revenue when the products are delivered to the midstream gathering or processing entity at a specified index price, net of downstream gathering and processing fees.

Asset Retirement Obligation:

The asset retirement obligation primarily represents the estimated present value of the amount the Company will incur to plug, abandon and remediate producing properties at the end of their productive lives, in accordance with applicable state laws. The Company determined its asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The asset retirement obligation is recorded as a liability at its estimated present value at its inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the statements of income.

Income Taxes:

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to turn around. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. As of December 31, 2022 and 2021, The Company had no valuation allowance.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties.

General and Administrative Expenses:

General and administrative expenses represent cost and expenses associated with the operation of the Company.

Earnings Per Common Share:

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per share amounts that would have resulted if dilutive potential common stock had been converted to common stock in gain periods.

Statements of Cash Flows:

For purposes of the consolidated statements of cash flows, the Company considers short-term, highly liquid investments with original maturities of less than ninety days to be cash equivalents.

Concentration of Credit Risk:

The Company maintains significant banking relationships with financial institutions in the State of Texas. The Company limits its risk by periodically evaluating the relative credit standing of these financial institutions. The Company's oil and gas production purchasers consist primarily of independent marketers and major gas pipeline companies.

Hedging:

The Company periodically enters into oil and gas financial instruments to manage its exposure to oil and gas price volatility. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

The financial instruments are accounted for in accordance with applicable accounting standards for derivative instruments and hedging activities. Such standards require that applicable derivative instruments be measured at fair market value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting applicable effectiveness guidelines, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss is recognized immediately in the statements of income.

2. Acquisitions and Dispositions

2022 Transactions:

In the first quarter of 2022, the Company sold 1,809 net leasehold acres in Reagan and Midland Counties, Texas through two separate transactions receiving gross proceeds of $14.0 million. In the second quarter of 2022, the Company sold 241 net acres in Canadian County, Oklahoma for $845,000. In the third quarter of 2022, the Company sold an additional 113 net acres in Canadian County, Oklahoma for $423,700.

On November 14, 2022, the Company completed an acreage exchange of approximately 725 net acres in the Midland Basin creating a block of 1,200 contiguous acres. The Company entered into an agreement, including this acreage, to create a 2,560-acre AMI for the joint development of horizontal wells. As part of the agreement, the Company sold a portion of its interest in this acreage to the joint development partner for proceeds of $16.1 million.

2021 Transactions:

During 2021 the Company acquired 5.9 net acres, located in Midland county, Texas, for approximately $29,500 and sold or farmed out interests in certain non-core undeveloped and developed oil and natural gas properties in Oklahoma. In Texas, the Company divested approximately 116 net mineral acres (NMA) located in Martin County, Texas for proceeds of $1.45 million.

During 2021 the Company liquidated partnerships for total cash payments of $632,000, resulting in the non-cash distribution of non-controlling interest of $647,000. Effective December 31, 2021, all managed partnerships and trusts were liquidated.

3. Additional Balance Sheet Information

Accounts receivable, net at December 31, 2022 and 2021 consisted of the following:

	December 31,	
(Thousands of dollars)	**2022**	**2021**
Joint interest billings	$ 1,806	$ 1,902
Trade receivables	1,762	1,429
Oil and gas sales	8,894	11,154
Other	21	94
	12,483	14,579
Less: Allowance for doubtful accounts	(336)	(371)
Total	$12,147	$14,208

Accounts payable at December 31, 2022 and 2021 consisted of the following:

	December 31,	
(Thousands of dollars)	2022	2021
Trade	$ 5,142	$2,390
Royalty and other owners	3,600	2,802
Partner advances	1,111	1,209
Other	1,598	881
Total	$11,451	$7,282

Accrued liabilities at December 31, 2022 and 2021 consisted of the following:

	December 31,	
(Thousands of dollars)	2022	2021
Compensation and related expenses	$ 9,743	$3,919
Property costs	6,413	2,901
Taxes	9,352	893
Other	242	108
Total	$25,750	$7,821

4. Long-Term Debt

Bank Debt:

On February 15, 2017, the Company and its lenders entered into a Third Amended and Restated Credit Agreement (the "2017 Credit Agreement") with a maturity date of February 15, 2021. Under the 2017 Credit Agreement, the Company had a revolving line of credit and letter of credit facility of up to $300 million subject to a borrowing base that is determined semi-annually by the lenders based upon the Company's consolidated financial statements and the estimated value of the Company's oil and gas properties, in accordance with the Lenders' customary practices for oil and gas loans. The credit facility is secured by substantially all of the Company's oil and gas properties. The 2017 Credit Agreement includes terms and covenants that require the Company to maintain a minimum current ratio and total indebtedness to EBITDAX (earnings before depreciation, depletion, amortization, taxes, interest expense and exploration costs) ratio, as defined, and restrictions are placed on the payment of dividends, the amount of treasury stock the Company may purchase, commodity hedge agreements, and loans and investments in its consolidated subsidiaries and limited partnerships.

On December 20, 2021 the company entered into a Seventh Amendment to the 2017 Credit Agreement and Citibank N.A was appointed as successor administrative agent replacing PNC Bank. Under this amendment the Company's borrowing base was $50 million. Borrowings under the 2017 Credit Agreement would bear interest at alternate base rate (ABR) plus an applicable margin ranging from 2.00% to 3.00% or at the Company's option, at a rate equal to the secured overnight financing rate (SOFR rate) as administered by the SOFR Administrator, in this case the Federal Reserve Bank of New York, plus an applicable margin ranging from 3.00% to 4.00%. The 2017 Credit Agreement was set to mature on February 11, 2023. On December 31, 2021, the Company had a total of $36 million of borrowings outstanding under its revolving credit and $14 million was available for future borrowings. The 2017 Credit Agreement was terminated on July 5th, 2022 with the issuance of the Fourth Amended and Restated Credit Agreement.

On July 5, 2022 , the Company and its lenders entered into a Fourth Amended and Restated Credit Agreement (the "2022 Credit Agreement") with a maturity date of June 1, 2026. Under the 2022 Credit Agreement, the Company has a revolving line of credit and letter of credit facility of up to $300 million subject to a borrowing base that is determined semi-annually by the lenders based upon the Company's consolidated financial statements and the estimated value of the Company's oil and gas properties, in accordance with the Lenders' customary practices for oil and gas loans. The initial borrowing base of the agreement is $75 million. The credit facility is secured by substantially all of the Company's oil and gas properties. The 2022 Credit Agreement includes terms and covenants that require the Company to maintain a minimum current ratio and total indebtedness to EBITDAX (earnings before depreciation, depletion, amortization, taxes, interest expense and exploration costs) ratio, as defined, and restrictions are placed on the payment of dividends, the amount of treasury stock the Company may purchase, and commodity hedge agreements.

On December 31, 2022, the Company had a total of $11 million of borrowings outstanding under its revolving credit facility and $64 million was available for future borrowings.

Effective January 20, 2023 , in lieu of a formal amendment, a borrowing base letter authorized by all lenders and Prime of the 2022 Credit Agreement resulted in an adjustment to decrease the amount of the Borrowing Base available from $75 million to $60 million until such time as the next redetermination date as required by the agreement.

As of March 31, 2023, the borrowing base was $60 million and the Company no outstanding borrowings under the Credit Facility.

Paycheck Protection Program Loans

During May 2020, Prime Operating Company and Eastern Oil Well Services Corporation, subsidiaries of the Company received loan proceeds in the amount of $1.28 million and $0.47 million, respectively, under the Paycheck Protection Program (the "PPP") of the CARES Act, which was enacted March 27, 2020. The PPP Loans are evidenced by a promissory note in favor of the Lender, which bears interest at the rate of 1.00% per annum. No payments of principal or interest are due under the note until the date on which the amount of loan forgiveness (if any) under the CARES Act, which can be up to 10 months after the end of the related notes covered period (which is defined as 24 weeks after the date of the loan) (the "Deferral Period"). The note may be prepaid at any time prior to maturity with no prepayment penalties. Funds from the PPP Loans may be used only for payroll and related costs, costs used to continue group health care benefits, mortgage payments, rent, utilities, and interest on other debt obligations that were incurred prior to February 15, 2020 (the "Qualifying Expenses"). Under the terms of the PPP Loans, certain amounts thereunder may be forgiven if they are used for Qualifying Expenses as described in and in compliance with the CARES Act. The Company utilized the PPP Loan proceeds exclusively for Qualifying Expenses during the 24-week coverage period and has submitted its application for forgiveness in accordance with the terms of the CARES Act and related guidance. In the event the PPP Loan or any portion thereof is forgiven, the amount forgiven is applied to the outstanding principal and accrued interest.

To the extent, if any, that any or all of the PPP loans are not forgiven, beginning one month following expiration of the Deferral Period, and continuing monthly until 24 months from the date of each applicable Note (the "Maturity Date"), the Company is obligated to make monthly payments of principal and interest to the Lender with respect to any unforgiven portion of the Note, in such equal amounts required to fully amortize the principal amount outstanding on such Note as of the last day of the applicable Deferral Period by the applicable Maturity Date.

The PPP loans have been approved for forgiveness by the Small Business Administration (SBA) in conjunction with our lender PNC Bank. The effective date of February 18, 2022 for Eastern Oil Well Service Company in the amount of $481 thousand in principal and interest paid to our lender PNC Bank. The effective date of March 16, 2022 for Prime Operating Company in the amount of $1.2 million in principal and interest to our lender PNC Bank. Effective December 31, 2021, PPP debt and any accrued interest were reclassed from the consolidated balance sheet and recorded in other income on the consolidated statements of income.

(5) Other Long-Term Obligations and Commitments:

Operating Leases:

The Company leases office facilities under operating leases and recognizes lease expense on a straight-line basis over the lease term. Lease assets and liabilities are initially recorded at commencement date based on the present value of lease payments over the lease term. A new finance lease for office equipment is included in Property and equipment, Current portion of asset retirement and Other Long-Term Obligations in 2022. As most of the Company's lease contracts do not provide an implicit discount rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. The weighted average discount rate used was 7.54%. Certain leases may contain variable costs above the minimum required payments and are not included in the right-of-use assets or liabilities. Leases may include renewal, purchase or termination options that can extend or shorten the term of the lease. The exercise of those options is at the Company's sole discretion and is evaluated at inception and throughout the contract to determine if a modification of the lease term is required. Leases with an initial term of 12 months or less are not recorded on the balance sheet.

Operating lease costs for the years ended December 31, 2022 and 2021 were $628 thousand and $577 thousand, respectively. Cash payments included in the operating lease cost for years ended December 31, 2022 and 2021 were $673 thousand and $599 thousand, respectively. The weighted-average remaining operating lease terms for the years ended December 31, 2022 and 2021 were 11 months and 15 months, respectively. The Company acquired and amended certain leases for office space in Texas providing for payments of $673,000 in 2022, $684,000 in 2023, $202,000 in 2024 and $27,000 in 2025.

Rent expense for office space the years ended December 31, 2022 and 2021 was $755,000 and $653,000, respectively.

The payment schedule for the Company's operating lease obligations as of December 31, 2022 is as follows:

(Thousands of dollars)	Operating Leases
2023	$684
2024	202
2025	27
Total undiscounted lease payments	$913
Less: Amount associated with discounting	(61)
Total net operating lease liabilities	$852
Less: Current portion included in Other current liabilities	647
Non-current portion included in Other liabilities	$205

Asset Retirement Obligation:

A reconciliation of the liability for plugging and abandonment costs for the years ended December 31, 2022 and 2021 is as follows:

(Thousands of dollars)	Years Ended December 31, 2022	2021
Asset retirement obligation at beginning of period	$14,295	$13,660
Net wells placed on production	11	724
Liabilities settled	(1,407)	(1,047)
Dispositions	(344)	(52)
Accretion expense	666	642
Revisions in estimated liabilities	2,222	368
Asset retirement obligation at end of period	$15,443	$14,295
Less: Current portion included in Current portion of asset retirement and other long-term obligations	1,918	1,073
Long-term Asset Retirement Obligations included in Asset Retirement Obligations	$13,525	$13,222

The Company's liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive life of wells and a risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of the Company's wells, the costs to ultimately retire the wells may vary significantly from previous estimates.

6. Contingent Liabilities

The Company is subject to environmental laws and regulations. Management believes that future expenses, before recoveries from third parties, if any, will not have a material effect on the Company's financial condition. This opinion is based on expenses incurred to date for remediation and compliance with laws and regulations, which have not been material to the Company's results of operations.

From time to time, the Company is party to certain legal actions arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

7. Stock Options and Other Compensation

In May 1989, non-statutory stock options were granted by the Company to four key executive officers for the purchase of shares of common stock. At December 31, 2021 and 2020, options on 767,500 shares were outstanding and exercisable at prices ranging from $1.00 to $1.25. According to their terms, the options have no expiration date.

8. Income Taxes

The components of the provision for income taxes for the years ended December 31, 2022 and 2021 are as follows:

(Thousands of dollars)	Years Ended December 31, 2022	Years Ended December 31, 2021
Current:		
Federal	$ 8,330	$ 81
State	774	59
Total current	9,104	140
Deferred:		
Federal	886	1,802
State	339	574
Total deferred	1,225	2,376
Total income tax provision	$10,329	$2,516

(Thousands of dollars)	At December 31, 2022	At December 31, 2021
Deferred Tax Assets:		
Accrued liabilities	$ 353	$ 80
Allowance for doubtful accounts	77	85
Derivative Contracts	223	1,272
Partnership basis difference	90	98
State Net operating loss carry-forwards	283	470
Total deferred tax assets	1,026	2,005
Deferred Tax Liabilities:		
Depletion and depreciation	40,994	40,748
Total deferred tax liabilities	40,994	40,748
Net deferred tax liabilities	$39,968	$38,743

The total provision for income taxes for the years ended December 31, 2022 and 2021 varies from the federal statutory tax rate as a result of the following:

(Thousands of dollars)	Years Ended December 31, 2022	Years Ended December 31, 2021
Expected tax expense	$12,389	$ 975
Net changes in deferred assets and liabilities	1,225	2,376
Permanent differences	870	(677)
State income tax, net of federal benefit	612	47
Provision to return adjustment	(4,765)	744
Tax Credits	—	(948)
Other, net	(2)	(1)
Total income tax provision	$10,329	$2,516

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes.

The Company is entitled to percentage depletion on certain of its wells, which is calculated without reference to the basis of the property. To the extent that such depletion exceeds a property's basis, it creates a permanent difference, which lowers the Company's effective rate. The availability of the percentage depletion deduction is phased out as an entity's production exceeds certain levels, and based on the Company's increasing production the percentage depletion deduction is becoming less significant.

The Company is allowed a credit against the Texas Franchise Tax based on net operating losses incurred in prior periods. The credits allowed are $89 thousand in the years 2020 through 2026. Any credits not utilized in a given year due to the allowable credit exceeding the tax liability may be carried forward. No credit may be carried forward past 2026. The value of the credit is calculated net of the federal income tax effect.

The Company has not recorded any provision for uncertain tax positions. The Company files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. The 2004, 2005, 2006, 2009 and 2017 federal income tax returns have been audited by the Internal Revenue Service. Returns for unexamined earlier years may be examined and adjustments made to the amount of percentage depletion and AMT credit carryforwards flowing from those years into an open tax year, although in general no assessment of income tax may be made for those years on which the statute has closed. Federal and State returns for the years 2020 through 2022 remain open for examination by the relevant taxing authorities.

Enactment of the Inflation Reduction Act of 2022. On August 16, 2022, President Biden signed into law the Inflation Reduction Act of 2022 (the "IRA"), which includes, among other things, a corporate alternative minimum tax (the "CAMT"). Under the CAMT, a 15 percent minimum tax will be imposed on certain adjusted financial statement income of "applicable corporations," which is effective for tax years beginning after December 31, 2022. The CAMT generally treats a corporation as an "applicable corporation" in any taxable year in which the "average annual adjusted financial statement income" of the corporation and certain of its subsidiaries and affiliates for a three taxable-year period ending prior to such taxable year exceeds $1 billion. The IRA also establishes a one percent excise tax on stock repurchases made by publicly traded U.S. corporations. The excise tax is effective for any stock repurchases after December 31, 2022. The IRA did not impact the Company's current year tax provision or the Company's consolidated financial statements, but the new provisions could impact future periods.

Enactment of the Consolidated Appropriations Act, 2021. On December 27, 2020, President Trump signed into law the Consolidated Appropriations Act, 2021 (the "Act"). The Act includes many tax provisions, including the extension of various expiring provisions, extensions and expansions of certain earlier pandemic tax relief provisions, among other things. The Act did not have a material impact on the Company's tax provisions or the Company's consolidated financial statements.

Enactment of the Coronavirus Aid, Relief and Economic Security Act. On March 27, 2020, President Trump signed into law the Coronavirus Aid, Relief and Economic Security Act ("CARES Act"). The CARES Act, among other things, includes provisions relating to refundable payroll tax credits, deferment of employer social security payments, net operating loss carryback periods, alternative minimum tax credit refunds, modifications to the net interest deduction limitations and technical corrections to tax depreciation methods for qualified improvement property. Under the CARES Act the refundable portion of AMT credits was increased to 100% therefore the Company received a full refund of such credits in 2020.

9. Segment Information and Major Customers

The Company operates in one industry – oil and gas exploration, development, operation and servicing. The Company's oil and gas activities are entirely in the United States. The Company sells its oil and natural gas and liquids production to a number of direct purchasers under direct contracts or through other operators under joint operating agreements. Listed below are the purchasers of the Company's production which represented more than 10% of the Company's sales for the years ended 2022 and 2021.

	2022	2021
Oil:		
APA Corporation	55%	48%
Plains All American Inc.	16%	18%
Natural gas and liquids:		
APA Corporation	58%	52%
Targa Pipeline Mid-Continent West Tex, LLC	11%	19%

Although there are no long-term oil and gas purchasing agreements with these purchasers, the Company believes that they will continue to purchase its oil and gas products and, if not, could be replaced by other purchasers.

10. Financial Instruments

Fair Value Measurements:

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value. The fair values of the Company's interest rate swaps, natural gas and crude oil price collars and swaps are designated as Level 3. The following fair value hierarchy table presents information about the Company's assets and liabilities measured at fair value on a recurring basis at December 31, 2022 and December 31, 2021:

December 31, 2022	Quoted Prices in Active Markets For Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2022
(Thousands of dollars)				
Assets				
Commodity derivative contracts	$—	$—	$ 210	$ 210
Total assets	$—	$—	$ 210	$ 210
Liabilities				
Commodity derivative contracts	$—	$—	$(1,190)	$(1,190)
Total liabilities	$—	$—	$(1,190)	$(1,190)

December 31, 2021	Quoted Prices in Active Markets For Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2021
(Thousands of dollars)				
Assets				
Commodity derivative contracts	$—	$—	$ —	$ —
Total assets	$—	$—	$ —	$ —
Liabilities				
Commodity derivative contract	$—	$—	$(5,585)	$(5,585)
Total liabilities	$—	$—	$(5,585)	$(5,585)

The derivative contracts were measured based on quotes from the Company's counterparties. Such quotes have been derived using valuation models that consider various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable.

These estimates are verified using comparable NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness.

The significant unobservable inputs for Level 3 derivative contracts include basis differentials and volatility factors. An increase (decrease) in these unobservable inputs would result in an increase (decrease) in fair value, respectively. The Company does not have access to the specific assumptions used in its counterparties' valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the year ended December 2022.

(Thousands of dollars)	
Net Liabilities – December 31, 2021	$ (5,585)
Total realized and unrealized gains (losses):	
Included in earnings (a)	(12,039)
Purchases, sales, issuances and settlements	16,644
Net Liabilities – December 31, 2022	$ (980)

(a) Derivative instruments are reported in revenues as realized gain/loss and on a separately reported line item captioned unrealized gain/loss on derivative instruments.

Derivative Instruments:

The Company is exposed to commodity price and interest rate risk, and management considers periodically the Company's exposure to cash flow variability resulting from the commodity price changes and interest rate fluctuations. Futures, swaps and options are used to manage the Company's exposure to commodity price risk inherent in the Company's oil and gas production operations. The Company does not apply hedge accounting to any of its commodity-based derivatives. Both realized and unrealized gains and losses associated with commodity derivative instruments are recognized in earnings.

The following table sets forth the effect of derivative instruments on the consolidated balance sheets at December 31, 2022 and 2021:

		Fair Value	
(Thousands of dollars)	**Balance Sheet Location**	**December 31, 2022**	**December 31, 2021**
Asset Derivatives:			
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contract	Other current assets	$ 162	$ —
Natural gas commodity contract	Other current assets	48	—
Total		$ 210	$ —
Liability Derivatives:			
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contracts	Derivative liability short-term	$ (931)	$(3,992)
Natural gas commodity contracts	Derivative liability short-term	(259)	(943)
Crude oil commodity contracts	Derivative liability long-term	—	(490)
Natural gas commodity contracts	Derivative liability long-term	—	(160)
Total		$(1,190)	$(5,585)
Total derivative instruments		$ (980)	$(5,585)

The following table sets forth the effect of derivative instruments on the consolidated statements of income for the years ended December 31, 2022 and 2021:

(Thousands of dollars)	Location of gain/loss recognized in income	Amount of gain/loss recognized in income 2022	2021
Derivatives not designated as cash-flow hedge instruments:			
Natural gas commodity contracts	Unrealized gain (loss) on derivative instruments, net	892	(859)
Crude oil commodity contracts	Unrealized (loss) gain on derivative instruments, net	3,713	(4,055)
Natural gas commodity contracts	Realized gain (loss) on derivative instruments, net	(4,543)	(1,833)
Crude oil commodity contracts	Realized (loss) on derivative instruments, net	(12,101)	(3,212)
		$(12,039)	$(9,959)

11. Related Party Transactions

During 2021 the Company, as managing general partner or managing trustee, repurchased the interests of the partners and trust unit holders in certain of the Partnerships or Trusts in an amount totaling $676,000. Effective December 31, 2021, all managed partnerships and trusts were liquidated.

Amounts due to or from related parties primarily represent receipts or expenses, related to oil and gas properties, collected or paid by the Company as agent for the joint venture partners, which may include members of the Company's Board of Directors.

12. Salary Deferral Plan

The Company maintains a salary deferral plan (the "Plan") in accordance with Internal Revenue Code Section 401(k), as amended. The Plan provides for matching contributions, of which $301,837 and $304,955 were made in 2022 and 2021, respectively

13. Earnings per Share

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per share amounts that would have resulted if dilutive potential common stock had been converted to common stock in gain periods. The following reconciles amounts reported in the consolidated financial statements:

	Years Ended December 31, 2022			2021		
	Net Income (In 000's)	Weighted Average Number of Shares Outstanding	Per Share Amount	Net Income (In 000's)	Weighted Average Number of Shares Outstanding	Per Share Amount
Basic	$48,664	1,953,916	$24.91	$2,098	1,992,077	$1.05
Effect of dilutive securities:						
Options	—	757,254			752,085	
Diluted	$48,664	2,711,170	$17.95	$2,098	2,744,162	$0.76

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

(Unaudited)

(Thousands of dollars)	As of December 31, 2022	2021
Proved Developed oil and gas properties	$ 555,280	$ 539,484
Proved Undeveloped oil and gas properties	—	—
Total Capitalized Costs	555,280	539,484
Accumulated depreciation, depletion and valuation allowance	(385,811)	(359,742)
Net Capitalized Costs	$ 169,469	$ 179,742

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

(Unaudited)

(Thousands of dollars)	Years Ended December 31, 2022	2021
Development Costs	$13,598	$18,678

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

(Unaudited)

(Thousands of dollars)	As of December 31, 2022	2021
Future cash inflows	$ 994,842	$ 501,431
Future production costs	(378,160)	(207,697)
Future development costs	(95,746)	(18,507)
Future income tax expenses	(110,439)	(57,798)
Future Net Cash Flows	410,497	217,429
10% annual discount for estimated timing of cash flows	(165,961)	(81,623)
Standardized Measure of Discounted Future Net Cash Flows	$ 244,536	$ 135,806

See accompanying Notes to Supplementary Information

PRIMEENERGY RESOURES CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN RELATING TO PROVED OIL AND GAS RESERVES

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2022 and 2021:

	Years Ended December 31,	
(Thousands of dollars)	**2022**	**2021**
Sales of oil and gas produced, net of production costs	$ (86,302)	$ (45,322)
Net changes in prices and production costs	72,640	143,750
Extensions, discoveries and improved recovery	126,029	6,440
Revisions of previous quantity estimates	(10,902)	18,991
Net change in development costs	(2,814)	(12,904)
Reserves sold	(818)	(136)
Reserves purchased	—	—
Accretion of discount	13,581	4,162
Net change in income taxes	(8,435)	(21,180)
Changes in production rates (timing) and other	5,751	386
Net change	108,730	94,187
Standardized measure of discounted future net cash flow:		
Beginning of year	135,806	41,619
End of year	$244,536	$135,806

See accompanying Notes to Supplementary Information

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

RESERVE QUANTITY INFORMATION
Years Ended December 31, 2022 and 2021

(Unaudited)

	As of December 31,					
	2022			2021		
	Oil (MBbls)	NGL's (MBbls)	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)
Proved Developed Reserves:						
Beginning of year	5,386	2,882	23,902	2,684	2,258	13,633
Extensions, discoveries and improved recovery	99	74	464	69	1	628
Revisions of previous estimates	(375)	(37)	1,309	1,639	813	11,836
Converted from undeveloped reserves	—	—	—	1,747	231	1,067
Reserves sold	(28)	(5)	(73)	(15)	(5)	(26)
Reserve purchased	—	—	—	—	—	—
Production	(939)	(417)	(3,325)	(738)	(416)	(3,236)
End of year	4,143	2,497	22,277	5,386	2,882	23,902
Proved Undeveloped Reserves:						
Beginning of year	—	—	—	1,784	787	3,897
Extensions, discoveries and improved recovery	3,028	1,833	9,030	(61)	(557)	(2,726)
Revisions of previous estimates	—	—	—	31	4	386
Converted to developed reserves	—	—	—	(1,747)	(231)	(1,067)
Reserves Sold	—	—	—	(7)	(4)	(489)
End of year	3,028	1,833	9,030	—	—	—
Total Proved Reserves at the End of the Year	7,171	4,330	31,307	5,386	2,882	23,902

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES
Years Ended December 31, 2022 and 2021

(Unaudited)

	Years Ended December 31,	
(Thousands of dollars)	2022	2021
Revenue:		
Oil and gas sales	$124,118	$73,126
Costs and Expenses:		
Lease operating expenses	37,816	27,804
Depreciation, depletion and accretion	28,068	26,325
Income tax expense	10,329	3,989
Total Costs and Expenses	76,213	58,118
Results of Operations from Producing Activities (excluding corporate overhead and interest costs)	$ 47,905	$15,008

See accompanying Notes to Supplementary Information

NOTES TO SUPPLEMENTARY INFORMATION
(Unaudited)

1. Presentation of Reserve Disclosure Information

Reserve disclosure information is presented in accordance with U.S. generally accepted accounting principles. The Company's reserves include amounts attributable to non-controlling interests in the Partnerships. These interests represent less than 10% of the Company's reserves.

2. Determination of Proved Reserves

The estimates of the Company's proved reserves were determined by an independent petroleum engineer in accordance with U.S. generally accepted accounting principles. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development and other factors. Estimated future net revenues were computed by reserves, less estimated future development and production costs based on current costs.

Proved reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that proved reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

3. Results of Operations from Oil and Gas Producing Activities

The results of operations from oil and gas producing activities were prepared in accordance with U.S. generally accepted accounting principles. General and administrative expenses, interest costs and other unrelated costs are not deducted in computing results of operations from oil and gas activities.

4. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes of standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with U.S. generally accepted accounting principles.

Future cash inflows are computed as described in Note 2 by applying current prices to year-end quantities of proved reserves.

Future production and development costs are computed estimating the expenditures to be incurred in developing and producing the oil and gas reserves at year-end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying the U.S. tax rate to future pre-tax cash inflows relating to proved oil and gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences and tax credits and allowances relating to the proved oil and gas reserves.

Future net cash flows are discounted at a rate of 10% annually (pursuant to applicable guidance) to derive the standardized measure of discounted future net cash flows. This calculation does not necessarily represent an estimate of fair market value or the present value of such cash flows since future prices and costs can vary substantially from year-end and the use of a 10% discount figure is arbitrary.

5. Changes in Reserves

The 2022 and 2021 extensions and discoveries reflect the drilling activity in the Company's West Texas and Mid-Continent areas. The Company is employing technologies to establish proved reserves that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data being used in the estimation of its proved reserves include, but are not limited to, electrical logs, radioactivity logs, geologic maps, production data and well test data. The estimated reserves of wells with sufficient production history are estimated using appropriate decline curves. Estimated reserves of producing wells with limited production history and for undeveloped locations are estimated using performance data from analogous wells in the area. These wells are considered analogous based on production performance from the same formation and with similar completion techniques. Future development plans are reflective of the current commodity prices and have been established based on an expectation of available cash flows from operations and availability under our revolving credit facility.

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Officers

Charles E. Drimal, Jr.
Chairman, President and
Chief Executive Officer

Beverly A. Cummings
Executive Vice President, Treasurer and
Chief Financial Officer

Virginia M. Forese
Corporate Secretary

Directors

Beverly A. Cummings
PrimeEnergy Resources Corporation

Charles E. Drimal, Jr.
PrimeEnergy Resources Corporation

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H. Gifford Fong
President
Gifford Fong Associates
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