PrimeEnergy

PrimeEnergy Resources Corporation

ANNUAL REPORT
2024

Chairman's Letter

Dear Shareholder,

In 2024, we continued to solidify our balance sheet and dramatically increased our proved developed reserves. We increased our proved developed oil reserves from 5,757,000 barrels to 7,444,000 barrels. We also increased our proved developed natural gas reserves from 24.75 BCF to 37.50 BCF and our total proved developed NGL reserves from 3,666,000 barrels to 6,597,000 barrels. We accomplished these exceptional results and still ended 2024 with just $4,000,000 of bank debt.

Our strategy is to be steadfast in our plan to strengthen our balance sheet and improve our liquidity position as we grow our reserve base. We were able to increase our Reserve Base Loan (RBL) from $85,000,000 to $115,000,000 in 2024 and believe that the availability under this facility will afford us the liquidity to execute our drilling program in 2025.

In 2024, the Company invested $113 million in 48 horizontals in West Texas: 47 of these are located in Reagan County and one is located in Upton County. In Reagan County, the Company joined Double Eagle in drilling and completing 33 new horizontal wells: on the "Honey RF" tract we completed 12 horizontals each being two-mile-long laterals, and participated with 50% interest investing $37 million; on the "Prime West" tract we have 50% interest in six wells and invested $20.5 million; on both the "Kramer" and "O'Bannion" tracts we participated in six horizontals, each with an average 8.3% interest and we invested approximately $7.8 million; and on the "Pink Floyd" tract we have less than 1% interest in two wells in which we invested approximately $174,900; and on our "Studley AV" tract we participated with Double eagle in testing the Wolfcamp "D" interval; in this well we have about 6.3% interest and invested approximately $600,000. Also in Reagan County, we participated with Civitas in 14 horizontal wells on the "Christi" tract, carrying an average of 39% interest and investing roughly $46.7 million. Also in 2024, in Upton County, we participated with Pioneer Natural Resources in one 2-mile-long horizontal with 3.94% interest, investing approximately $425,800. Of these 48 wells, 32 are 2-mile-long laterals, 14 are 2.5-mile-long laterals, and two are 3-mile-long laterals.

In addition to this activity, in June of 2024, we began participation with Apache in the drilling of six additional 3-mile-long laterals in Upton County on our "Mt. Moran" tract. Three of these wells were completed in late December 2024 and three were completed in January of 2025. All six new "Mt. Moran" wells are producing as of April 1, 2025. In these six Mt. Moran wells, the Company has an average of 51.16% interest and will in total invest approximately $40.5 million. In addition, in November of 2024, in Reagan County, we began participating with Double Eagle in 15 "OG" horizontal wells: eight are 2.5-mile-long laterals, and seven are 2-mile-long laterals. In each of these 15 "OG" wells the Company has approximately 23% interest and in total will invest roughly $29 million through completion of production facilities. These 15 horizontals are expected to be on production in mid to late April 2025. By the end of the second quarter of 2025, therefore, the Company will have invested approximately $70 million in these additional 21 horizontal wells.

In early March 2025, Ovintiv Mid-Continent spud two "Jennifer 1407" wells in Canadian County, Oklahoma; in these, we will participate for approximately 3.125% interest and invest $408,000. In the second and third quarters of 2025, we are anticipating the start of twenty new horizontals in the Midland Basin of West Texas: 15 wells operated by Double Eagle on our "Full House" tract in Reagan County in which the Company will participate with approximately 31% interest and invest $48.4 million, and five wells operated by ConocoPhillips on our "Schenecker" tract in Martin, County in which we plan to participate for 20.83% interest and invest $11.3 million. In total in these 22 wells, we will invest approximately $60 million.

The Company's horizontal development activities in the last two years, along with our projected activity for 2025, can be summarized as follows: in 2023 we invested $96 million in 35 horizontals, in 2024 we invested $113 million in 48 horizontals, and in 2025, we expect to invest $129 million in 43 horizontals. Therefore, in total, since January 2023 and through 2025, the Company will have invested roughly $338 million in horizontal development, primarily in the Midland Basin of West Texas. It is also noteworthy, that since the start of our horizontal development activities in 2012 the Company has invested over $430 million in horizontal drilling in the Midland Basin of West Texas, and $45 million in Oklahoma, predominantly in the Scoop/Stack Play.

Additional future drilling activity on our leasehold acreage in West Texas is expected over the next few years. In particular, based on activity west of our acreage in Reagan County, and a recent deep test by Double Eagle on our joint leasehold, we anticipate that proposals will soon be put forward for the drilling of between 36 and 45 new horizontals that will target the Wolfcamp “D” pay zone in Reagan County, and perhaps an additional test well or two in one or more of the other undeveloped pay horizons. In this future activity, we would expect to invest over $100 million. In addition, the Company has identified 20 horizontal locations across our acreage in Upton and Martin counties that could be drilled in this same time frame. These additional 20 wells will require an investment of approximately $64 million. In total, therefore, with the $60 million investment in the wells expected to begin drilling in 2025, the $100 million in Wolfcamp “D” development, plus $64 million in 20 additional near-term wells expected to occur in the 2026-2027 timeframe, we anticipate investing approximately $224 million in horizontal drilling in West Texas over the next several years.

In West Texas and eastern New Mexico, we maintain an acreage position of approximately 17,138 gross (9,483 net) acres, 89.3% of which are located in Reagan, Upton, and Martin counties of Texas where our current West Texas horizontal drilling activities are focused. In addition to the wells currently being drilled or completed, we believe this acreage has the resource potential to support the drilling of as many as 100 future horizontal wells.

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 43 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. 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 (ORRI). Regarding the 13 wells drilled in 2023, we chose to farm-out our interest and own an ORRI in these wells. The Company plans to participate with Ovintiv Mid-Continent in the drilling of two 2-mile-long horizontals in Canadian County, Oklahoma with 3.125% interest, investing roughly $408,000 through completion. Also in 2024, the Company earned an ORRI interest in five wells in Canadian County, with an average of 0.9% in each of three wells and 3% in two wells, and earned a 0.034% ORRI in one well in Major County.

In 2024 we continued our share repurchase program and retired 113,630 shares which represent approximately 6% of the outstanding shares. In the first quarter of 2025, we retired 36,000 shares and plan to continue our repurchase program throughout the year which is dependent on the price of our shares and the company’s liquidity position.

Throughout the last 35 years, our share repurchase program has returned approximately $114,000,000 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 1,672,500 shares outstanding. We have now retired approximately seventy-eight percent (78%) of the outstanding shares of the company. In 199, we also retired 697,500 options which today would represent 28% of the fully diluted outstanding shares of the company. The cost to retire those options was $607,000, $0.87 per share.

PrimeEnergy remains committed to developing its reserves, principally in the Permian basin. Ultimately, a corporation is dependent on the people within and we believe that we have those people in place to facilitate the continued growth of our business.

The annual Meeting of Shareholders will be held at our office at 9821 Katy Freeway, Suite 1050 Houston, Texas on June 5, 2025, 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

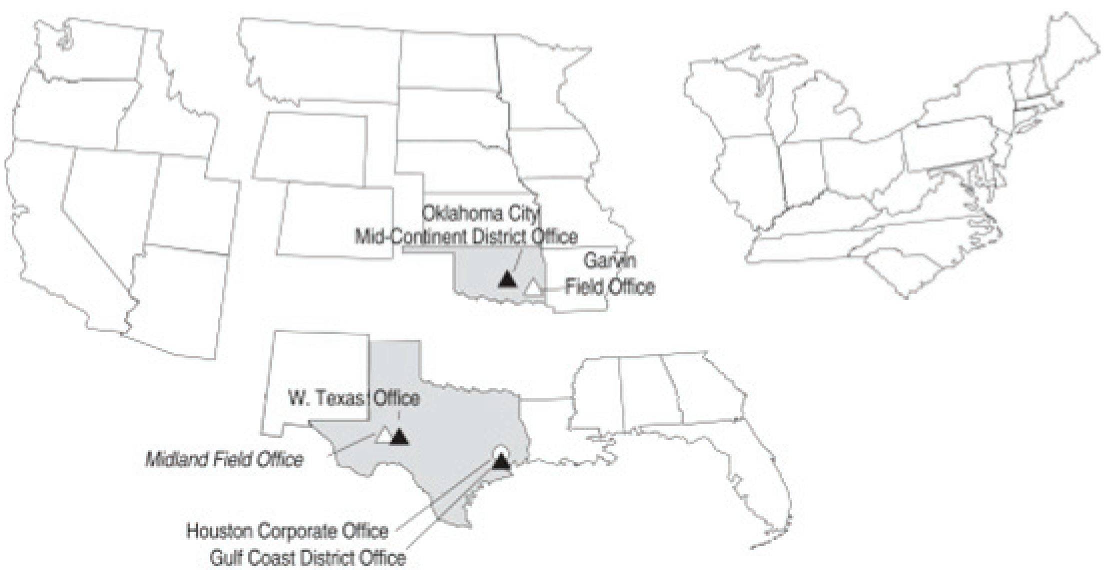
Charles E. Drimal, Jr.
Chairman and Chief Executive Officer

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 507 active wells and owns non-operating and royalty interests in over 1,054 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, 2024, as filed with the Securities and Exchange Commission is reproduced herein (except for exhibits) as the Company's Annual Report for 2024 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.

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, 2024

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 Stock Market**

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

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

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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 $66,363,685.

The number of shares outstanding of the registrant's Common Stock, par value $0.10 per share, as of April 8, 2025, was 1,672,470.

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 5, 2025, are incorporated by reference in Part III hereof.

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Definitions of Certain Terms and Conventions Used Herein

Within this Report, the following terms and conventions have specific meanings:

Measurements.

- ***"Bbl"*** means a standard barrel containing 42 United States gallons.
- ***"BOE"*** means a barrel of oil equivalent and is a standard convention used to express oil and gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of six thousand cubic feet of gas to one Bbl of oil or natural gas liquid.
- ***"BOEPD"*** means BOE per day.
- **"Btu"** means British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- ***"MBbl"*** means one thousand Bbls.
- ***"MBOE"*** means one thousand BOEs.
- ***"Mcf"*** means one thousand cubic feet and is a measure of gas volume.
- ***"MMcf"*** means one million cubic feet.

Indices.

- ***"Brent"*** means Brent oil price, a major trading classification of light sweet oil that serves as a benchmark price for oil worldwide.
- ***"WAHA"*** is a benchmark pricing hub for West Texas gas.
- ***"WTI"*** means West Texas Intermediate, a light sweet blend of oil produced from fields in western Texas and is a grade of oil used as a benchmark in oil pricing. General terms and conventions.
- ***"DD&A"*** means depletion, depreciation and amortization.
- ***"ESG"*** means environmental, social and governance.
- ***"GAAP"*** means accounting principles generally accepted in the United States of America.
- ***"GHG"*** means greenhouse gases.
- ***"LNG"*** means liquefied natural gas.
- ***"NGLs"*** means natural gas liquids, which are the heavier hydrocarbon liquids that are separated from the gas stream; such liquids include ethane, propane, isobutane, normal butane and natural gasoline.
- **"NYMEX"** means the New York Mercantile Exchange.
- ***"OPEC"*** means the Organization of Petroleum Exporting Countries.
- ***"PrimeEnergy"*** or the "Company" means PrimeEnergy Resources Corporation and its subsidiaries.
- ***"Proved developed reserves"*** means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.
- ***"Proved reserves"*** means those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to

extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

- ***"Proved undeveloped reserves*"** means 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

- ***"SEC*"** means the United States Securities and Exchange Commission.

- ***"Standardized Measure*"** means the after-tax present value of estimated future net cash flows of proved reserves, determined in accordance with the rules and regulations of the SEC, using prices and costs employed in the determination of proved reserves and a 10 percent discount rate.

- ***"U.S.*"** means United States.

- With respect to information on the working interest in wells, drilling locations and acreage, "***net***" wells, drilling locations and acres are determined by multiplying "***gross***" wells, drilling locations and acres by the Company's working interest in such wells, drilling locations or acres. Unless otherwise specified, wells, drilling locations and acreage statistics quoted herein represent gross wells, drilling locations or acres.

- ***"WASP*"** means weighted average sales price.

- All currency amounts are expressed in U.S. dollars.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This information in 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 PrimeEnergy Resources Corporation "The Company" 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 material 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 ongoing conflicts in Ukraine and the Middle East) or 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 rates or laws, new restrictions on development activities or potential changes in regulations limiting produced water disposal; 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 on global and U.S. economic activity, oil and gas demand, and global and U.S. supply chains; 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; the Company's ability to achieve its emissions reductions, flaring and other ESG sustainability goals; access to and cost of capital; the financial strength of (i) counterparties to The Company's credit facility and derivative contracts, (ii) issuers of the Company's investment securities and (iii) purchasers of the Company's oil, NGL and gas production and downstream sales of purchased commodities; 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, and cash flow from downstream purchases and sales of oil and gas, net of firm transportation commitments; 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 "Part I, Item 1. Business — Competition," "Part I, Item 1. Business —Regulation," "Part I, Item 1A. Risk Factors," "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk" in this Report for a description of various factors that could materially affect the ability of 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. The Company undertakes no duty to publicly update these statements except as required by law.

PrimeEnergy Resources Corporation

FORM 10-K ANNUAL REPORT
For the Fiscal Year Ended
December 31, 2024

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 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 currently idle 60-mile-long pipeline offshore on the shallow shelf of Texas. 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 $40,000 as of December 31, 2024. There is currently no debt on the shopping center and it has approximately $700,000 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, the Company 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.

Information contained on the Company's website is not part of or incorporated into this Report or any other filings with the SEC.

Exploration, Development, and Recent Activities

The Company's goal is to responsibly develop its oil and gas reserves, predominantly through horizontal drilling. Our 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 2025, we will continue our focus on preserving financial flexibility and 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.

Horizontal development of our leasehold acreage has continued at a fast pace, particularly in West Texas, where in 2024 we participated with Double Eagle, Pioneer, Civitas, and ConocoPhillips in the drilling and completion of 56 new horizontal wells targeting the Wolfcamp and Spraberry producing intervals. There are at least six pay intervals ("benches") being developed in the Midland Basin, from the deeper Wolfcamp "D" up through the shallower Middle Spraberry. The economic variability from one area to another and from one well to another depends on geologic properties (thickness, porosity, permeability, and hydrocarbon maturity), lateral length, stimulation, and oil price, as well as the economies of scale and therefore cost advantages often achieved by the more active operators. Under our leasehold acreage in the Midland Basin, several of these benches have either never been tested, or not yet developed, however, near our acreage, some of these benches have just recently been aggressively developed. We estimate that our acreage in Reagan, Upton, and Martin counties has the potential for as many as 100 drilling locations for these benches that we believe will likely be drilled in the next several years. In particular, under our large acreage position in Reagan County, only the Wolfcamp "A" and "B" intervals have been developed so far, along with a one-well test of the Wolfcamp "D" on one block, which is encouraging. We, therefore, see significant potential for near-term development of one or more productive intervals in the Wolfcamp "D", Jo Mill, Lower Sprabbery, and Middle Spraberry.

Currently, in Upton County, we are participating with Apache Corporation in six 3-mile-long horizontals that targeted the Upper Wolfcamp and the Jo Mill benches. These six wells were all completed before February 1, 2025, and are producing as of April 1, 2025. The following is a detailed description of the recent and expected near-term drilling activities.

In 2023, the Company completed 35 horizontal wells operated by five operators: 32 of these are located in West Texas and three in Oklahoma. In total, including the cost of facilities, the Company invested approximately $96 million, 99% of which was for wells in West Texas where we have been developing various proven pay intervals in the Wolfcamp and Spraberry formations. Below is a recap of our horizontal development activity in 2023.

In Reagan County, Texas we participated with Hibernia Energy II (Now Civitas) in ten 2-mile-long horizontals carrying 25% interest and investing $25.6 million. These ten wells on our "Brynn" tract began production in April 2023. Also in Reagan County in 2023, we participated with DE IV, LLC (Double Eagle) in 15 horizontals and invested approximately $34.8 million: five of these were 2-mile-long laterals on the "Prime East" tract that were placed on production in May 2023, in which we have nearly 50% interest, another six 2-mile-long laterals on the "Studley AV" tract that were brought on production in December 2023 in which we have 7% interest, and four 2.5-mile laterals on the "Studley CKO" tract that were completed in December 2023 in which we have 20% interest. These 25 Reagan County wells were all completed in 2023.

In Upton County, Texas, we participated for 50% interest in two 3-mile-long horizontals operated by Apache. These were brought into production in October 2023 and required an investment of approximately $17 million through completion of the wells and central facilities. In Martin County, Texas in 2023, we participated with ConocoPhillips for 20.8% interest in five 2.5-mile-long horizontal laterals, investing approximately $12 million. These five were completed and brought online in September 2023. Also in 2023, in Oklahoma, we joined Ovintiv USA, Inc. in the drilling of three 3-mile-long horizontals located in Canadian County with 2% interest and invested approximately $645,000.

In 2024, the Company invested $113 million in 48 horizontals in West Texas: 47 of these are located in Reagan County and one is located in Upton County. In Reagan County, the Company joined Double Eagle in drilling and completing 33 new horizontal wells: on the "Honey RF" tract we completed 12 horizontals each being two-mile-long laterals, and participated with 50% interest investing $37 million; on the "Prime West" tract we have 50% interest in six wells and invested $20.5 million; on both the "Kramer" and "O'Bannion" tracts we participated in six horizontals, each with an average 8.3% interest and we invested approximately $7.8 million; and on the "Pink Floyd" tract we have less than 1% interest in two wells in which we invested approximately $174,900; and on our"Studley AV" tract we participated with Double eagle in testing the Wolfcamp "D" interval; in this well we have about 6.3% interest and invested approximately $600,000. Also in Reagan County, we participated with Civitas in 14 horizontal wells on the "Christi" tract, carrying an average of 39% interest and investing roughly $46.7 million. Also in 2024, in Upton County, we participated with Pioneer Natural Resources in one 2-mile-long horizontal with 3.94% interest, investing approximately $425,800. Of these 48 wells, 32 are 2-mile-long laterals, 14 are 2.5-mile-long laterals, and two are 3-mile-long laterals.

In addition to this activity, in June of 2024, we began participation with Apache in the drilling of six additional 3-mile-long laterals in Upton County on our "Mt. Moran" tract. Three of these wells were completed in late December 2024 and three were completed in January of 2025. All six new "Mt. Moran" wells are producing as of April 1, 2025. In these six Mt. Moran wells, the Company has an average of 51.16% interest and will in total invest approximately $40.5 million. In addition, in November of 2024, in Reagan County, we began participating with Double Eagle in 15 "OG" horizontal wells: eight are 2.5-mile-long laterals, and seven are 2-mile-long laterals. In each of these 15 "OG" wells the Company has approximately 23% interest and in total will invest roughly $29 million through completion of production facilities. These 15 horizontals are expected to be on production in mid to late April 2025. By the end of the second quarter of 2025, therefore, the Company will have invested approximately $70 million in these additional 21 horizontal wells.

In early March 2025, Ovintiv Mid-Continent spud two "Jennifer 1407" wells in Canadian County, Oklahoma; in these, we will participate for approximately 3.125% interest and invest $408,000. In the second and third quarters of 2025, we are anticipating the start of twenty new horizontals in the Midland Basin of West Texas: 15 wells operated by Double Eagle on our "Full House" tract in Reagan County in which the Company will participate with approximately 31% interest and invest $48.4 million, and five wells operated by ConocoPhillips on our "Schenecker" tract in Martin, County in which we plan to participate for 20.83% interest and invest $11.3 million. In total in these 22 wells, we will invest approximately $60 million.

The Company's horizontal development activities in the last two years, along with our projected activity for 2025, can be summarized as follows: in 2023 we invested $96 million in 35 horizontals, in 2024 we invested $113 million in 48 horizontals, and in 2025, we expect to invest $129 million in 43 horizontals. Therefore, in total, since January 2023 and through 2025, the Company will have invested roughly $338 million in horizontal development, primarily in the Midland Basin of West Texas. It is also noteworthy, that since the start of our horizontal development activities in 2012 the Company has invested over $430 million in horizontal drilling in the Midland Basin of West Texas, and $45 million in Oklahoma, predominantly in the Scoop/Stack Play.

Additional future drilling activity on our leasehold acreage in West Texas is expected over the next few years. In particular, based on activity west of our acreage in Reagan County, and a recent deep test by Double Eagle on our joint leasehold, we anticipate that proposals will soon be put forward for the drilling of between 36 and 45 new horizontals that will target the Wolfcamp "D" pay zone in Reagan County, and perhaps an additional test well or two in one or more of the other undeveloped pay horizons. In this future activity, we would expect to invest over $100 million. In addition, the Company has identified 20 horizontal locations across our acreage in Upton and Martin counties that could be drilled in this same time frame. These additional 20 wells will require an investment of approximately $64 million. In total, therefore, with the $60 million investment in the wells expected to begin drilling in 2025, the $100 million in Wolfcamp "D" development, plus $64 million in 20 additional near-term wells expected to occur in the 2026-2027 timeframe, we anticipate investing approximately $224 million in horizontal drilling in West Texas over the next several years.

In West Texas and eastern New Mexico, we maintain an acreage position of approximately 17,138 gross (9,483 net) acres, 89.3% of which are located in Reagan, Upton, and Martin counties of Texas where our current West Texas horizontal drilling activities are focused. In addition to the wells currently being drilled or completed, we believe this acreage has the resource potential to support the drilling of as many as 100 future horizontal wells.

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 43 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. 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 (ORRI). Regarding the 13 wells drilled in 2023, we chose to farm-out our interest and own an ORRI in these wells. The Company plans to participate with Ovintiv Mid-Continent in the drilling of two 2-mile-long horizontals in Canadian County, Oklahoma with 3.125% interest, investing roughly $408,000 through completion. Also in 2024, the Company earned an ORRI interest in five wells in Canadian County, with an average of 0.9% in each of three wells and 3% in two wells, and earned a 0.034% ORRI in one well in Major County.

Significant Activity

As of December 31, 2024, we had net capitalized costs related to proved oil and gas properties of $294 million. Total expenditures for the acquisition, exploration, and development of our properties during 2024 were $119 million as we continue development under the programs discussed above. Proved reserves as of December 31, 2024, were 26,512 MBOE which consisted of 76.5% proved developed reserves and 23.5% proved undeveloped reserves.

The Company is actively participating in 21 horizontals in West Texas spud in the middle of 2024 that have been drilled in Spraberry and Wolfcamp producing intervals. In total, the Company will invest an estimated $68.5 million in these 21 wells: Six operated by Apache, which were placed on production in March 2025 and the remaining 15, operated by Double Eagle, are to be on production in April 2025. In addition, in the first quarter of 2025, we began participating in two horizontals with Ovintiv Mid-Continent in Canadian County, Oklahoma with a working interest share of 3.125% interest and will invest approximately $408,000. In the second and third quarters of 2025, we expect to begin participation in two development projects in West Texas with 20.83% interest in the drilling of five wells in Martin County, operated by ConocoPhillips, and with 31% interest in 15 wells in Reagan County operated by Double Eagle. Total investment in these is estimated to be $48.5 million.

In 2024, the Company raised proceeds of $4.2 million from the sale of acreage, producing properties, and an equipment company subsidiary, and we acquired $3.88 million worth of acreage in West Texas for future development.

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 acquisition and 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 through a wholly owned subsidiary, we own a significant amount 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 508 wells, including producing, saltwater disposal, injection, and supply wells: 32 through the Houston office, 321 through the Midland office, and 155 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.

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

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 in the United States 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 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 outlining federal jurisdictional reach under the CWA over waters of the U.S., including wetlands, which has since been subject to several revisions. In May 2023, the Supreme Court decided *Sackett v. EPA*, which significantly narrowed the scope of "waters of the United States." Under Sackett, the jurisdictional "waters" refers only to "those relatively permanent, standing or continuously flowing bodies of water forming geographic features that are described in ordinary parlance as streams, oceans, rivers, and lakes" and to "wetlands that are as a practical matter indistinguishable from waters of the United States." In August 2023, the EPA finalized a rule amending the definition of "waters of the United States" to conform with the recent Supreme Court decision in *Sackett*. Litigation challenging the EPA's rule and aspects of the January 2023 definition not addressed by *Sackett* is ongoing. To the extent future changes expand 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.

Given the long-term trend toward increasing regulation, these and future laws and 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. In December 2023, the EPA finalized New Source Performance Standard ("NSPS") Subpart OOOOb, which seeks to reduce methane and volatile organic compound emissions from the oil and natural gas source category and NSPS Subpart OOOOc, which create, for the first-time, emission guidelines for existing oil and natural gas sources that would be included in individual states' implementation plans. These standards expand upon previously issued NSPS Subparts OOOO and OOOOa published by the EPA in 2012 and 2016, respectively. President Trump's Administration has diverged, and is expected to continue to diverge, from the prior Biden Administration's positions including by promulgating new or amended regulations that are supportive of oil and natural gas development

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. 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; however, the BLM rescinded the 2015 rule in 2017.

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, or prohibit hydraulic fracturing or high volume hydraulic fracturing altogether. 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. In 2023, Recently, the FWS proposed that the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, be listed as endangered 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 2024, nor do we anticipate that such expenditures will be material in 2025.

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

Since the worldwide economic downturn in mid-2020, while oil prices have improved with demand steadily increasing, worldwide oil inventories, from a historical perspective, remain low. In addition, 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 ongoing 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. In March 2025, OPEC and certain other oil-producing countries (“OPEC+”) announced a plan to start increasing crude oil output starting in April 2025, which includes the gradual unwinding beginning in April 2025 of OPEC's MMBOPD production cut that started in July 2023. Economic volatility and geopolitical tensions have resulted in global supply chain disruptions, which has led to significant cost inflation. 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, tariffs and import bans on production from Russia and other countries, (iii) the timing and supply impact of any Iranian sanction relief on their ability to export oil, (iv) the global supply chain constraints associated with manufacturing and distribution delays, (v) oilfield service demand and cost inflation, and (vi) political stability of oil consuming countries and oil producing regions. 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 2024.

Oil Purchasers:	
DE IV Operating, LLC	44.09%
Civitas Resources Inc...	19.57%
APA Corporation.	11.90%
Gas Purchasers:	
DE IV Operating, LLC	29.77%
Civitas Resources Inc	21.79%
APA Corporation.	18.64%

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, 2024, we had 78 full time employees, 30 of whom were employed at our principal offices in Houston, Texas, at the offices of Prime Operating Company, and EOWS Midland Company, and 48 employees who were primarily involved in our district operations in Midland, Texas and Elmore City and Oklahoma City, Oklahoma.

Item 1A. RISK FACTORS

General 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 $2.13 per MMBTU in 2024 as compared to $2.637 per MMBTU in 2023, and have averaged $3.89 per MMBTU for the first three months of 2025. Oil prices, based on West Texas Intermediate(WTI) Light Sweet Crude first-of-the-month prices, averaged $75.48 per barrel in 2024 as compared to $78.22 per barrel in 2023, and in the first three months of 2025, the first-of-the-month price has averaged $69.67 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;
- the domestic and foreign supply of natural gas and oil
- weather conditions and natural disasters;
- political conditions in natural gas and oil producing regions, including the Middle East, Russia, Africa and South America;
- actions by the members of the Organization of Petroleum Exporting Countries with respect to oil production levels and announcements of potential changes in such levels;
- the price levels, including any changes to tariffs, and quantities of foreign imports to the United States;
- 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;
- conservation and environmental protection efforts, including activities by non-governmental organizations to restrict the exploration, development and production of natural gas and oil;
- overall economic conditions; and
- global or national health concerns, including the outbreak of pandemic or contagious disease.

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, ongoing conflict in Ukraine and 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 continued volatility in both credit and commodity markets, 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.

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.

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, GHG emissions, climate change 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. In addition, investors currently focused on the potential effectives of climate change may elect to shift some or all of their investments into non-fossil fuel energy related investments. Limitation of investments in and financings for fossil fuel energy could restrict the availability of capital, resulting in the restriction, delay, or cancellation of development and production activities.

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.

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. If there were insufficient capacity available on these facilities, if these facilities were unavailable to the Company or if access to these facilities were to become commercially unreasonable, the price offered for the Company's production could be significantly depressed, or the Company could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons while it constructs its own facility or awaits the availability of third party facilities. The Company also relies (and expects to rely in the future) on facilities developed and owned by third parties in order to gather, store, process, transport, fractionate, refine, export and sell its oil, NGL and gas production. The Company's plans to develop and sell production from its oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient gathering, transportation, storage, processing, fractionation, refining or export facilities to the Company, especially in areas of planned expansion where such facilities do not currently exist. 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.

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.

A failure of technology systems, data breach or cyber incident 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, cyber and other security threats are constantly evolving, thereby making it more difficult to successfully defend against them or to implement adequate preventative measures. 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 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.

In addition to the risks presented to our systems and networks, cyber-attacks affecting oil and natural gas distribution systems maintained by third parties, or the networks and infrastructure on which they rely, could delay or prevent delivery of our production to markets. Further, cyber-attacks on a communications network or power grid could cause operational disruption resulting in loss of revenues. A cyber-attack of this nature would be outside our control, but could have a material, adverse effect on our business, financial condition and results of operations.

Risks Related to our Business

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;
- lack of available capacity on interconnecting transmission pipelines;
- lack of available drilling and production equipment or availability of oil field labor;
- compliance with, or changes in, governmental requirements and regulation, including with respect to wastewater disposal, discharge of GHGs 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. In addition, there are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and the assumption of potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates.

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.

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 $115 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 2025 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 2025 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

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. Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities, other property or natural resources, clean-up responsibilities, regulatory investigations and penalties and suspension of operations.

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.

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.

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.

Legal and Regulatory Risks

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 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, new or more stringent regulations may be promulgated in the future.

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. In the absence of federal actions, states may elect to become more active in regulating or even could elect to prohibit hydraulic fracturing or high volume hydraulic fracturing altogether, following the approach taken by the states of Vermont, Maryland, Washington 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, which has since been subject to several revisions. In August 2023, the EPA finalized a rule amending the definition of "waters of the United States" to conform with the recent Supreme Court decision in *Sackett v. EPA*. However, litigation challenging the EPA rulemaking and aspects of the January 2023 definition not addressed by *Sackett* is ongoing. To the extent that future changes to the definition expand the scope of the CWA'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 Company's operations are subject to a number of risks arising out of concerns regarding the threat of climate change.

The Company’s operations are subject to a number of risks arising out of concerns regarding the threat of climate change, including regulatory and litigation risks, that could, among other things, result in increased operating costs and costs of compliance, limit the areas in which oil and gas production may occur, expose the Company to the risk of increased activism or reduce demand for the oil and gas the Company produces.

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. For example, in December 2023, the EPA finalized NSPS Subpart OOOOb, which seeks to reduce methane and volatile organic compound emissions from the oil and natural gas source category and NSPS Subpart OOOOc, which create, for the first-time, emission guidelines for existing oil and natural gas sources that would be included in individual states’ implementation plans. These standards expand upon previously issued NSPS Subparts OOOO and OOOOa published by the EPA in 2012 and 2016, respectively. 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. In January 2025, President Trump signed an executive order to withdraw the United States from the Paris Agreement. While the current U.S. administration may diverge from the prior administration’s positions and could withdraw from or otherwise roll back existing GHG emissions regulations, it is not possible at this time to predict exactly which and to what extent such regulations will be modified, and how any such actions may impact our business. Further, such actions could prompt more activity from state and local legislative bodies and administrative agencies to pass stricter GHG emissions laws, regulations, and other binding commitments.

Litigation risks relating to GHG emissions and climate change are 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.

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 change, 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 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.

Increasing scrutiny and changing expectations from investors, lenders and other market participants with respect to our Environmental, Social and Governance ("ESG") policies may impose additional costs on us or expose us to additional risks.

Companies across all industries continue to face scrutiny relating to their ESG policies. Investor advocacy groups, certain institutional investors, investment funds, lenders and other market participants, often focus on ESG practices and in recent years have placed increasing importance on the implications and social cost of their investments. At the same time, some stakeholders and regulators have increasingly expressed or pursued opposing views, legislation, and investment expectations with respect to ESG, including the enactment or proposal of "anti-ESG" legislation or policies. Our ESG practices and related disclosures may be subject to increased scrutiny and may not satisfy the requirements of all stakeholders or their requirements may not be made known to us. The increased focus and activism related to ESG and similar matters may hinder access to capital, as investors and lenders may decide to reallocate capital or not to commit capital as a result of their assessment of a company's ESG practices. Companies that do not adapt to or comply with investor, lender or other industry shareholder expectations and standards, which are evolving and may be conflicting, or which are perceived to have not responded appropriately to such stakeholder's concern, regardless of whether there is a legal requirement to do so, may suffer from reputational damage and the business, financial condition or stock price of such a company could be materially and adversely affected.

Additionally, certain investors and lenders have and may continue to exclude companies engaged in exploration and production activity, such as us, from their investing portfolios altogether due to ESG factors. These limitations in both the debt and equity capital markets may affect our ability to grow as our plans for growth may include accessing those markets. If those markets are unavailable, or if we are unable to access alternative means of financing on acceptable terms, or at all, we may be unable to implement our business strategy, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Further, we may incur additional costs and require additional resources to monitor, report and comply with ESG requirements that may be adopted. The occurrence of any of the foregoing could have a material adverse effect on our business and financial condition.

Changes to the U.S. federal tax laws could adversely affect our financial position, results of operations and cash flow.

Our future effective tax rates could be adversely affected by changes in tax laws, both domestically and internationally, or the interpretation or application thereof. From time to time, U.S. and foreign tax authorities, including state and local governments consider legislation that could increase our effective tax rate.

The IRA includes a 1% tax on publicly traded corporations on the fair market value of stock repurchased during any taxable year. Such tax applies to the extent such buybacks exceed $1 million during such year, which buyback value may be offset by other stock issuances.

Further, the U.S. Congress has advanced a variety of tax legislation proposals, and while the final form of any legislation is uncertain, the current proposals, if enacted, could have a material effect on our effective tax rate. Additionally, in recent years, lawmakers and the U.S. Department of the Treasury have proposed certain significant changes to U.S. tax laws applicable to oil and gas companies. These changes include, but are not limited to; (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. This legislation or any future similar changes in U.S. federal income tax laws, as well as any similar changes in state law, could eliminate or postpone certain tax deductions that currently are available with respect to natural gas and oil exploration and production, which could negatively affect our results of operations and financial condition.

Item 1B. UNRESOLVED STAFF COMMENTS.

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

Item 1C. CYBERSECURITY

As an oil and gas producer, the Company is dependent on digital technology in many areas of its business and operations. Additionally, the Company gathers and safeguards sensitive information as a part of its regular business activities. The Company continually evaluates and integrates new processes, systems and resources to enhance its defenses against cybersecurity threats.

Governance

The Board is responsible for overseeing the Company's enterprise risk management processes and has delegated oversight of cybersecurity and other information technology risks to the Executive Committee, a standing committee of the Board. The Executive Committee oversees management's implementation and execution of the Company's Cybersecurity Program and IRP. The Executive Committee receives in-depth annual reports from the Director of Information Technology (DIT) or Assistant Director of Information Technology (ADIT)detailing relevant cybersecurity risks to the Company and, as necessary, timely periodic updates based on circumstances, regarding any significant cybersecurity incidents or developments. The Executive Committee reports to the Board regarding its activities, including those related to cybersecurity.

At the management level, the Company's cybersecurity governance includes a Cybersecurity Steering Committee which is comprised of a subset of the Company's Executive Committee and other key officers, leaders, and subject matter experts from various disciplines across the Company. The Cybersecurity Steering Committee meets quarterly to receive updates from the DIT and/or ADIT on Company-related cyber risks, monitor compliance with the Company's Cyber Security Program, and to review cybersecurity policies.

The Company’s cybersecurity risk management and strategy processes are managed by the DIT and the ADIT who have 40 and 20 years of work experience, respectively, in various roles involving systems security, operations and compliance. These individuals are informed about and monitor the prevention, detection, mitigation and remediation of cybersecurity incidents through their management of internal information technology personnel and retained third-party personnel involved in the cybersecurity risk management and strategy processes described above, including the operation of the IRP.

Cybersecurity Program Management

The Company has developed and implemented an information security program (the Cybersecurity Program), which includes various processes and controls intended to protect the confidentiality, integrity and availability of the Company's systems and information. We have also implemented an incident response plan (the IRP) that applies in the event of a cybersecurity threat or incident to provide a standardized framework for responding to security incidents. The IRP sets out a coordinated approach to investigating, containing, documenting and mitigating incidents, including reporting findings and keeping senior management and other key stakeholders informed and involved as appropriate.

The Company’s Cybersecurity Program and incident response processes were primarily designed and assessed to align with the cybersecurity framework published by the National Institute of Standards and Technology. In addition to our internal cybersecurity capabilities, the Company retains or engages various third-parties in connection with design, implementation and monitoring of certain cybersecurity-related processes and controls.

Key aspects of the Company’s Cybersecurity Program include:

- Risk assessments designed to help identify material cybersecurity risks to critical systems and the company-wide information technology environment;
- Continuous monitoring of Company systems and conducting periodic penetration tests;
- An IRP that includes procedures for responding to cybersecurity incidents;
- Required cybersecurity trainings for employees, incident response personnel, and management related to physical security of assets, data privacy and other information security policies and procedures; and
- A third-party risk management process for its service providers, suppliers, vendors and other business associates.

The Cybersecurity Program is integrated into the Company’s overall enterprise risk management process and shares common methodologies, reporting channels, and governance processes that apply across the enterprise risk management process to other legal, compliance, strategic, operational, and financial risk areas. Cyber risks identified in the overall enterprise risk management process are reviewed annually by the Executive Committee.

Risks from Cybersecurity Threat

As of the date of this Annual Report on Form 10-K, the Company has not identified any cybersecurity incidents, including any prior cybersecurity incidents, that have materially affected the Company's operations, business strategy, results of operations and cash flows. The Company faces various ongoing risks from cybersecurity threats that, if realized, are reasonably likely to lead to losses of sensitive information, critical infrastructure or capabilities essential to the Company's operations and could have a material adverse effect on the Company's reputation, financial position, results of operations and cash flows. See "Item 1A. Risk Factors - The Company's business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions" for additional information.

Item 2. PROPERTIES.

Our executive offices, as well as offices of Prime Operating 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 Midland, Texas, as well as, Garvin, 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, 2024.

	2024		2023		2022	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Oil	—	—	—	—	—	—
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Development:						
Oil	59	18.74	35	8.37	8	0.76
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total:						
Oil	59	18.74	35	8.37	8	0.76
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
	59	18.74	35	8.37	8	0.76

Oil and Gas Production

As of December 31, 2024, we had ownership interest in the following number of gross and net producing oil and gas wells(1).

	Gross	Net
Producing Oil Wells(1)	789	33
Producing Gas Wells(1)	206	384

(1) A gross well is a well in which a working interest is owned. A net well is the sum of the fractional working 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, 2024. “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.

	2024	2023	2022
Oil (barrels)	2,556,000	1,144,000	939,000
NGL (barrels)	1,284,000	606,000	417,000
Gas (Mcf)	7,766,000	4,127,000	3,325,000

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, 2024.

	2024	2023	2022
Average sales price per barrel of oil	$ 75.80	$ 76.84	$ 96.70
Average sales price per barrel of NGL	$ 20.25	$ 19.64	$ 35.70
Average sales price per Mcf of natural gas	$ 0.43	$ 1.93	$ 5.54
Average production costs per net equivalent barrel of oil(1)	$ 9.29	$ 12.98	$ 16.07

(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:

	2024	2023	2022
Average sales price per barrel of oil	$ 75.80	$ 76.33	$ 87.77
Average sales price per barrel of NGL	$ 20.25	$ 19.64	$ 35.70
Average sales price per Mcf of natural gas	$ 0.43	$ 1.93	$ 4.44

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, 2024. “Undeveloped acreage” is 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	84,153	24,832	-	-	84,153	24,832
Mineral fee acreage	1,640	117	19,257	417	20,897	534
Total	85,793	24,949	19,257	417	105,050	25,366

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, 2024, is zero acres for the year ending December 31, 2025, zero in 2026, and zero acres in 2027.

Reserves

All of 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, 2024. 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 districts consist of degreed engineers and geologists with over twenty-five years of industry experience and between ten 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. 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)
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
2023	5,757	3,676	24,749	13,558	6,254	5,156	24,470	15,488	12,011	8,832	49,219	29,046
2024	7,444	6,597	37,489	20,288	3,166	1,670	8,326	6,224	10,610	8,267	45,815	26,512

(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 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.

At year-end 2022, the Company had 6,366 Mboe of proved undeveloped reserves attributable to 20 horizontal wells, located in West Texas that before year-end were in the process of being drilled by three separate operators: In Martin County, five 2.5-mile-long horizontal wells were being drilled in which the Company has 20.83% interest and an expected capital investment of $12.1 million; In Reagan County, the Company was participating in 10 two-mile horizontals operated by Hibernia Energy III (now Civitas Resources) in which the Company has a 25% interest and required approximately $25.6 million in investment and was also participating with Double Eagle (DE IV) in five two-mile-long horizontals with slightly less than 50% interest, carrying a net capital outlay of $23.4 million. All twenty of these West Texas horizontals were completed in 2023 and online in the second quarter of that year.

In 2023, the Company partnered with four operators in the drilling of 57 horizontal wells: 54 of these located in West Texas and three located in Oklahoma. At year-end 2023, 23 of these wells had been completed and the remaining 34 were completed in 2024. In those wells completed in 2023 the Company invested approximately $42.8 million and in the 34 remaining West Texas wells completed in 2024, the total investment, including central facilities, was approximately $81.3 million. At year-end 2023, six of the 34 wells completed in 2024 were categorized as probable undeveloped, therefore, their non-proved reserves were not included in the reserve report that reported only proved reserves. At year-end 2023, the Company had 15,489 MBOE of proved undeveloped reserves attributable to 52 undeveloped wells, 42 of which were in the process of being drilled or completed at year-end.

In 2024, the Company invested $113 million in drilling and completion of 48 new horizontals in West Texas: 47 of these are located in Reagan County, and one is located in Upton County. In Reagan County, the Company joined Double Eagle in 33 new horizontals with an average 28.2% interest and invested approximately $66 million. Also in Reagan County, we participated with Civitas in 14 horizontals on the "Christi" tract, carrying an average of 39% interest and investing roughly

$46.7 million. Also in 2024, in Upton County, we participated with Pioneer Natural Resources in one 2-mile-long horizontal with 3.94% interest, investing approximately $425,700.

At year-end 2024, the Company was participating in 21 horizontals in West Texas. Of these 21 wells, six are located in Upton County, operated by Apache Corporation; three of the six were completed by year-end and three were completed after the first of the year and all were brought online in April, 2025. The remaining 15 of the 21 wells, located on our "OG" tracts and operated by Double Eagle, were in the process of being drilled or completed at year-end and are expected to be on production by June 2025. At year-end 2024, the Company had 6,224 MBOE of proved undeveloped reserves attributable to 33 undeveloped wells, 18 of which were in the process of being drilled or completed at year-end and 15 of which are slated for drilling in the third quarter of 2025.

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, 2024, 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
2022	$ 320,146	$ 192,688	$ 200,790	$ 118,081	$ 520,936	$ 310,769	$ 66,233	$ 244,536
2023	$ 314,415	$ 213,281	$ 253,959	$ 138,679	$ 568,374	$ 351,960	$ 73,912	$ 278,048
2024	$ 389,266	$ 280,595	$ 111,451	$ 65,030	$ 500,716	$ 345,626	$ 72,581	$ 273,045

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 $2.13 per MMBtu in 2024 as compared to $2.64 per MMBtu in 2023 and $6.36 per MMBtu in 2022. Oil prices, based on the West Texas Intermediate (WTI) Light Sweet Crude first-of-the-month average spot price, were $75.48 per barrel in 2024 as compared to $78.22 per barrel in 2023, and $93.67 per barrel in 2022. Since January 1, 2023, 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, 2024.

	Gulf Coast	Mid-Continent	West Texas	Other	Total
Proved Reserves as of December 31, 2024 (MBoe)					
Developed	452	2,643	17,159	35	20,288
Undeveloped	—	—	6,224	—	6,224
Total	452	2,643	23,383	35	26,512
Average Net Daily Production (Boe per day)	143	806	13,749	9	14,707
Gross Productive Wells (Working Interest and ORRI Wells)	124	518	652	219	1,513
Gross Productive Wells (Working Interest Only)	73	359	543	75	1,050
Net Productive Wells (Working Interest Only)	24	159	274	4	461
Gross Operated Productive Wells	28	117	315	—	460
Gross Operated Water Disposal, Injection and Supply wells	4	38	6	—	48

In West Texas, we have a field service group 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, saltwater disposal facilities, and trucks we own that are operated by our field employees.

Gulf Coast Region

Our production and development activities in the Gulf Coast region are concentrated in southeast and east Texas. This region is managed from our office in Houston, Texas. Principal producing intervals are in the Wilcox, Hackberry, and Yegua formations at depths ranging from 6,000 to 12,000 feet. We had 73 producing wells (24 net) in the Gulf Coast region as of December 31, 2024, of which 28 wells are operated by us. Average net daily production in our Gulf Coast Region at year-end 2024 was 143 Boe. At December 31, 2024, we had 452 MBoe of proved reserves in the Gulf Coast region, which represented 1.7% of our total proved reserves. We maintain an acreage position of over 7,468 gross (4,699 net) acres in this region, primarily in Colorado, Newton, and Polk counties. In October of 2024, on the San Pedro Ranch in Dimmit County, Texas, we finished plugging-out all of our wells, removing all surface equipment, and reclaiming the land. With assistance from an operator in the area, we were able to do so at minimal expense to the Company. By plugging out our wells on this property we were able to extinguish about $2.7 million in future plugging liability.

Currently, we are monitoring the drilling and near-term completion plans of a new well drilled by Ventex Operating, on acreage in the Segno field of Polk County, Texas where the Company farmed-out its 55% leasehold rights for cash and a 5.53% over-riding royalty interest (ORRI). The well was cased in February 2025 and the operator intends to test one or more prospective intervals in the well.

As of March 31, 2025, the Gulf Coast region has plans to recomplete three producing wells: the Wing #16, the Sarah F. Wing #80, and the Sarah F. Wing #85 wells in the Segno field of Polk County, Texas, at an expense of approximately $341,000 in total. Other than these recompletions, we currently have 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, 2024, we had 359 producing wells (159 net) in the Mid-Continent area, of which 117 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. The average net daily production in our Mid-Continent Region in 2024 was 806 Boe. On December 31, 2024, we had 2,643 MBoe of proved reserves in the Mid-Continent area, representing 10% of our total proved reserves. We maintain an acreage position of approximately 45,715 gross (10,102 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 Scoop and Stack plays of Oklahoma where drilling is primarily targeting reservoirs of the Mississippian, and Woodford formations. In Canadian County, Oklahoma, we have agreed to participate with Ovintiv Mid-Continent in the drilling of two 2-mile-long horizontal wells which were spud in early March 2025. Our share of these wells will be 3.125% and the total investment will be on the order of $408,000. Also in Canadian County, we had a small ORRI in four wells drilled in the first quarter of 2025 by Camino Natural Resources.

West Texas Region

Our West Texas activities are concentrated in the Permian Basin in Texas. The oil and gas in this basin 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, 2024, we had 543 wells (274 net) in the West Texas area, of which 315 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. The average net daily production in our West Texas Region at year-end 2024 was 13,749 Boe. On December 31, 2024, we had 23,383 MBoe of proved reserves in the West Texas area, or 88.3% of our total proved reserves. We maintain an acreage position of approximately 17,138 gross (9,484 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, and one kill truck. Oil field support is provided for drilling and workover operations both to third-party operators as well as for our own operated wells and locations.

At year-end 2024, the Company was participating with Double Eagle in the drilling or completion of 15 horizontal wells in Reagan County, Texas with an average of 23% interest, and participating with Apache Corporation in six wells in Upton County, Texas with 51.2% interest. Three of the six Apache wells were completed by year-end and are categorized in the reserve report as proved developed non-producing and the other three, along with the 15 wells operated by Double Eagle, are categorized as proved undeveloped. In total, we expect to spend approximately $69.4 million in these 21 horizontals and their associated facilities.

Future drilling activity on our leasehold acreage in West Texas is expected in the next few years as well. In particular, based on activity west of our acreage in Reagan County, and a recent deep test by Double Eagle on our joint leasehold, we anticipate that proposals will soon be put forward for the drilling of between 36 and 45 new horizontals that will target the Wolfcamp "D" pay zone in Reagan County and perhaps an additional test well or two in one or more of the other undeveloped pay horizons. In this future activity, we would expect to invest in excess of $100 million. The Company is currently participating with 3.125% interest in two wells in Canadian County, Oklahoma, Operated by Ovintiv Mid-Continent, and plans to spend $408,000, Also, in 2025 we plan to join Double Eagle in the drilling of 15 wells in Reagan County, Texas with 31% interest, investing roughly $48.3 million, and in Martin County, Texas we plan to participate with Conoco-Phillips in the drilling of five wells with 20.8% interest, investing roughly 11.3 million. In addition, the Company has identified 20 horizontal locations across our acreage in Upton and Martin counties that could be drilled in this same time frame. These additional 20 wells will require an investment of approximately $64 million. In total, therefore, with approximately $60 million to be invested in the various wells drilling or to begin drilling in 2025, the $100 million in Wolfcamp "D" development, and the $64 million in 20 other near-term wells expected in the 2026-2027 timeframe, we anticipate investing approximately $224 million in horizontal drilling in West Texas over the next several years.

Item 3. LEGAL PROCEEDINGS.

In the ordinary course of conducting our business, we become involved in litigation and other claims from private party actions, as well as judicial and administrative proceedings involving governmental authorities at the federal, state, and local levels. While the outcome of litigation or other proceedings against us cannot be predicted with certainty, management does not expect that any loss resulting from such litigation or other proceedings, in excess of any amounts accrued or covered by insurance, will have a material adverse impact on our consolidated financial statements.

Item 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II—OTHER INFORMATION

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".

As of April 8, 2025 there were 189 registered holders of the common stock.

We have not paid any dividends during the three most recent fiscal years or any subsequent interim period, and we do not intend to pay any cash dividends in the foreseeable future. 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 Sales and Purchases of Equity Securities

There were no sales of equity securities by the Company during the period covered by this report. The following table details the Company's purchases of shares for the three months ended December 31, 2024**.**

2024 Month	Total Number of Shares Purchased	Average Price Paid per share	Maximum Number of Shares That May Yet Be Purchased Under The Program at Month-End (1)
October	9,500	$ 153.52	171,014
November	1,200	$ 200.49	169,814
December	7,800	$ 191.02	162,014
Total/Average	18,500	$ 172.38	

(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, June 13, 2018 and June 7, 2023, the Board of Directors of the Company approved an additional 500,000, 200,000 and 300,000 shares respectively, of the Company's stock to be included in the stock repurchase program. A total of 4,000,000 shares have been authorized to date under this program. Through December 31, 2024, a total of 3,837,986 shares have been repurchased under this program for $103,416,456 at an average price of $26.95 per share. The stock repurchase program has no specific term. 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.

PART II—OTHER INFORMATION

Item 6. RESERVED

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 been volatile in recent years 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, and available capacity under our revolving credit facility.

Net cash provided by operating activities for the year ended December 31, 2024, was $115.9 million compared to $109.0 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 2025, we will continue our focus on preserving financial flexibility and liquidity as we manage the risks facing our industry. Our 2025 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 December 20, 2028, providing for a credit facility totaling $300 million, with a borrowing base of $115 million. As of April 8, 2025, the Company had $17.5 million in outstanding borrowings and $97.5 million in availability under this facility. The bank reviews the borrowing base semi-annually and, at its 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 June 2025. 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 requires us to hedge a portion of our production as forecasted for the PDP reserves included in our borrowing base review engineering reports. The credit agreement requires that as of the last day of any fiscal quarter, if the borrowing base utilization percentage on such a date is less than 15%, then the borrower shall not be required to enter into any swap agreements. As of the quarter ended December 31, 2024, the Company had $4 million in outstanding borrowings and $111 million in availability. Accordingly, the Company had no swap agreements in place for oil and natural gas.

Development and Other Activities

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 2024, the Company invested $113 million in 48 horizontals in West Texas: 47 of these are located in Reagan County and one is located in Upton County. In Reagan County, the Company joined Double Eagle in drilling and completing 33 new horizontal wells: on the "Honey RF" tract we completed 12 horizontals each being two-mile-long laterals, and participated with 50% interest investing $37 million; on the "Prime West" tract we have 50% interest in six wells and invested $20.5 million; on both the "Kramer" and "O'Bannion" tracts we participated in six horizontals, each with an average 8.3% interest and we invested approximately $7.8 million; and on the "Pink Floyd" tract we have less than 1% interest in two wells in which we invested approximately $174,900; and on our"Studley AV" tract we participated with Double eagle in testing the Wolfcamp "D" interval; in this well we have about 6.3% interest and invested approximately $600,000. Also in Reagan County, we participated with Civitas in 14 horizontal wells on the "Christi" tract, carrying an average of 39% interest and investing roughly $46.7 million. Also in 2024, in Upton County, we participated with Pioneer Natural Resources in one 2-mile-long horizontal with 3.94% interest, investing approximately $425,700. Of these 48 wells, 32 are 2-mile-long laterals, 14 are 2.5-mile-long laterals, and two are 3-mile-long laterals.

In addition to this activity, in June of 2024, we began participation with Apache in the drilling of six additional 3-mile-long laterals in Upton County on our "Mt. Moran" tract. Three of these wells were completed in late December 2024 and three were completed in January of 2025. All six new "Mt. Moran" wells are producing as of April 1, 2025. In these six Mt. Moran wells, the Company has an average of 51.16% interest and will in total invest approximately $40.5 million. In addition, in November of 2024, in Reagan County, we began participating with Double Eagle in 15 "OG" horizontal wells: eight are 2.5-mile-long laterals, and seven are 2-mile-long laterals. In each of these 15 "OG" wells the Company has approximately 23% interest and in total will invest roughly $29 million through completion of production facilities. These 15 horizontals are expected to be on production in mid to late April 2025. By the end of the second quarter of 2025, therefore, the Company will have invested approximately $70 million in these additional 21 horizontal wells.

In early March 2025, Ovintiv Mid-Continent spud two "Jennifer 1407" wells in Canadian County, Oklahoma; in these, we will participate for approximately 3.125% interest and invest $408,000. In the second and third quarters of 2025, we are anticipating the start of twenty new horizontals in the Midland Basin of West Texas: 15 wells operated by Double Eagle on our "Full House" tract in Reagan County in which the Company will participate with approximately 31% interest and invest $48.4 million, and five wells operated by ConocoPhillips on our "Schenecker" tract in Martin, County in which we plan to participate for 20.83% interest and invest $11.3 million. In total in these 22 wells, we will invest approximately $60 million.

During 2024, to supplement cash flow and finance our future drilling programs, the Company sold 120 net mineral acres and 10 surface acres in Midland and Ector counties, Texas. For these, we received $1,386,000 in gross proceeds. In addition, we divested 37 producing and two saltwater injection wells in various counties of New Mexico and Texas. These divestments have extinguished a substantial amount in future plugging liability. Also in 2024, we sold our South Texas oil field services company, Eastern Oil Well Service, for proceeds of $2.8 million. Included with this sale were extensive oil field service equipment and transport trucks, as well as two commercial saltwater disposal wells. Acquisitions in 2024, entailed the purchase of 381 net leasehold acres in West Texas for approximately $3.9 million.

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 2024 and 2023 was $13.4 million and $7.5 million, respectively. The Company expects continued spending under the stock repurchase program in 2025.

Results of Operations

2024 and 2023 Compared

We reported a net income of $55.4 million for 2024, or $31.43 per share, compared to $28.1 million, or $15.19 per share for 2023. The current year net income reflects production increases offset by commodity price decreases. The significant components of income and expense are discussed below.

Oil, NGL and gas sales increased $115 million, or 107.01% to $223.1 million for the year ended December 31, 2024 from $107.7 million for the year ended December 31, 2023. 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 decreased an average of $1.04 per barrel, or 1.35% on crude oil, increased an average of $0.61 per barrel, or 3.11% on NGL and decreased $1.49 per Mcf, or 77.6% on natural gas during 2024 as compared to 2023.

Our crude oil production increased by 1,412,000 barrels, or 123.43% to 2,556,000 barrels for the year ended December 31, 2024 from 1,144,000 barrels for the year ended December 31, 2023. Our NGL production increased by 678,000 or 111.88% to 1,284,000 for the year ended December 31, 2024 from 606,000 barrels for the year ended December 31, 2023. Our natural gas production increased by 3,639 MMcf, or 88.18% 7,766 MMcf for the year ended December 31, 2024 from 4,127 MMcf for the year ended December 31, 2023. 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, 2024 and 2023 (excluding realized gains and losses from derivatives).

	Years ended December 31, 2024	Years ended December 31, 2023	Increase / (Decrease)	Increase / (Decrease)
Barrels of Oil Produced	2,556,000	1,144,000	1,412,000	123.43%
Average Price Received	$ 75.80	$ 76.84	$ (1.04)	(1.35)%
Oil Revenue (In 000's)	$ 193,737	$ 87,906	$ 105,831	120.39%
Mcf of Gas Sold	7,766,000	4,127,000	3,639,000	88.18%
Average Price Received	$ 0.43	$ 1.92	$ (1.49)	(77.60)%
Gas Revenue (In 000's)	$ 3,309	$ 7,935	$ (4,626)	(58.30)%
Barrels of Natural Gas Liquids Sold	1,284,000	606,000	678,000	111.88%
Average Price Received	$ 20.25	$ 19.64	$ 0.61	3.11%
Natural Gas Liquids Revenue (In 000's)	$ 25,996	$ 11,901	$ 14,095	118.44%
Total Oil & Gas Revenue (In 000's)	$ 223,042	$ 107,742	$ 115,300	107.01%

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 2024 and 2023:

	Years ended December 31, 2024	2023
Oil derivatives - realized gains (losses)	$ 0	$ 179
Oil derivatives – unrealized gains	0	--
Total gains (losses) on oil derivatives	$ 0	$ 179
Natural gas derivatives – realized gains (losses)	0	235
Natural gas derivatives – unrealized gains	0	--
Total gains (losses) on natural gas derivatives	$ 0	$ 235
Total gains (losses) on oil and natural gas	$ 0	$ 414

Prices received for the years ended December 31, 2024 and 2023, respectively, including the impact of derivatives were:

	2024	2023	Increase / (Decrease)	Increase / (Decrease)
Oil Price	$ 75.80	$ 76.33	$ (0.53)	(0.69)%
Gas Price	$ 0.43	$ 1.93	$ (1.50)	(77.72)%
NGL Price	$ 20.25	$ 19.64	$ 0.61	3.11%

Oil and gas production expense increased $15.8 million, or 49.6% to $47.7 million for the year ended December 31, 2024 from $31.9 million for the year ended December 31, 2023. These changes reflect the cost savings related to wells that have been plugged offset by rising service costs and additional costs related to the new wells that have been placed on production.

Field service income decreased $4.5 million or 29.5% to $10.9 million for the year ended December 31, 2024 from $15.4 million for the year ended December 31, 2023. Workover rig services, hot oil treatments, saltwater hauling and disposal represent the bulk of our field service operations. These changes reflect decreases in equipment utilization related to the sale of Eastern Oil Well Service Company, effective August 31, 2024.

Field service expense decreased $2.6 million, or 22.4% to $9.1 million for the year ended December 31, 2024 from $11.7 million for the year ended December 31, 2023. Field service expenses primarily consist of wages and vehicle operating expenses. These changes reflect decreases in equipment utilization related to the sale of Eastern Oil Well Service Company, effective August 31, 2024.

Depreciation, depletion, and amortization increased $45.5 million, or 147.0% to $76.5 million for the year ended December 31, 2024 from $31.0 million for the year ended December 31, 2023. These increases reflect the expense related to the new wells placed on production during the twelve months ended December 31, 2024.

General and administrative expense increased $3.2 million, or 21.0% to $18.8 million for the year ended December 31, 2024 from $15.6 million for the year ended December 31, 2023. This increase is primarily due to employee compensation, benefits and other corporate costs.

Gain on sale and exchange of assets of $3.7 million for the year ended December 31, 2024 consists of sales of net mineral and surface acres in various locations in Texas and Oklahoma as well as the sale of our South Texas oilfield service company, Eastern Oil Well Service.

Interest expense increased $1.0 million, or 189.0% to $1.5 million for the year ended December 31, 2024 from $0.5 million for the year ended December 31, 2023. This increase reflects the higher interest and fee rates combined with borrowings throughout the twelve months of 2024 under our revolving credit agreement.

Tax expense of $15.8 million and $6.1 million were recorded for the years ended December 31, 2024 and 2023, respectively. The change in our income tax provision was primarily due to the increase in pre-tax income for the year ended December 31, 2024.

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, 2024 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, 2024.

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, 2024. 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.

As a result of this assessment, management concluded that, as of December 31, 2024, our internal control over financial reporting was effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. 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, 2024 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. OTHER INFORMATION.

None.

Item 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS.

Not applicable.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information relating to the Company's Directors, nominees for Directors and executive officers and the Company's insider trading policy will be included in the Company's definitive proxy statement relating the Company's Annual Meeting of Stockholders to be held in June 5, 2025, and which is incorporated herein by reference.

Code of Conduct and Ethics

We have adopted a Code of Business Ethics and Conduct (the "Code") that applies to all officers and employees. The Code is publicly available under the governance tab of our website at www.primeenergy.com. Any amendments to, or waivers of, the Code with respect to our principal executive officer, principal financial officer or principal accounting officer or controller, or persons performing similar functions, will be disclosed on our website within four business days following the date of the amendment or waiver. Copies of the Code may also be requested in print by writing to PrimeEnergy Resources Corporation, 9821 Katy Freeway, Suite 1050, Houston, TX 77024.

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 5, 2025, 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 5, 2025, 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 5, 2025, 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 5, 2025, 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 - All Financial Statement Schedules have been omitted because the required information is included in the Consolidated Financial Statements or the notes thereto, or because it is not required.

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).
4.1	PrimeEnergy Resources Corporation Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934, (filed as exhibit 4.1 of PrimeEnergy Resources Corporation Annual Report on Form 10-K for the year ended December 31, 2023, and incorporated 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 and incorporated by reference.
10.22.6.2	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 9, 2024, among PrimeEnergy Resources Corporation, Citibank, N.A., as administrative agent, the guarantors and the lenders party thereto (filed as exhibit 10.22.6.2) of PrimeEnergy Resources Corporation Form 8-K on February 13, 2024, and incorporated by reference.
10.22.6.3	THIRD AMENDMENT TO FOURTH AMENDED AND RESTATED CREDIT AGREEMENT, dated as of July 29, 2024, among PRIMEENERGY RESOURCES CORPORATION, a Delaware corporation (the “Borrower”), CITIBANK, N.A., as administrative agent (in such capacity, the “Administrative Agent”), each Guarantor party hereto, the Existing Lenders and the New Lender (filed as exhibit 10.22.6.3 of PrimeEnergy Resources Corporation Current Report on Form 8-K filed on August 1, 2024, and incorporated by reference.
10.22.6.4	FOURTH AMENDMENT TO FOURTH AMENDED AND RESTATED CREDIT AGREEMENT, dated as of December 20, 2024, among PRIMEENERGY RESOURCES CORPORATION, a Delaware corporation (the “Borrower”), CITIBANK, N.A., as administrative agent (in such capacity, the “Administrative Agent”), each Guarantor party hereto, the Existing Lenders (filed herewith)
19.1	Insider Trading Policy (filed herewith).
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 (furnished 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 (furnished herewith).
97.1	PrimeEnergy Resources Corporation Compensation Recoupment (CLAWBACK) Policy, (filed as exhibit 97.1 PrimeEnergy Resources Corporation Annual Report on Form 10-K for the year ended December 31, 2023, and incorporated by reference).
99.1	Summary Reserve Report dated February 14, 2025, 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)

Item 16. FORM 10-K SUMMARY.

None.

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 15 day of April, 2025.

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 15, day of April, 2025.

/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

GRASSI

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, 2024 and 2023, 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, 2024 and 2023, 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 of Oil and Gas Properties

Critical Audit Matter Description
At December 31, 2024, the carrying value of the Company's oil and gas properties was $293.9 million, and depreciation, depletion and amortization ("DD&A") expense was $76.5 million for the year then ended. As described in Note 1, under the successful efforts method of accounting, capitalized costs of proved properties are depleted using the units of production method based on proved reserves, as estimated by independent petroleum engineers. Proved reserve estimates are impacted by various inputs, including historical production, oil and gas price assumptions, and future operating and capital cost assumptions, among

other factors. Because of the complexity involved in estimating oil and gas reserves, the Company utilized independent petroleum engineers for the year ended December 31, 2024.

Auditing the Company's DD&A 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 the Critical Audit Matter was Addressed in the Audit
Our audit procedures related to the evaluation of DD&A of oil and gas properties included the following, among others:

- We obtained an understanding and evaluated the design of the Company's controls over its process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data utilized by the engineers in estimating oil and gas reserves.
- We evaluated 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 evaluated the methodologies and assumptions utilized by the Company's independent engineers to ensure they were reasonable and in accordance with industry standards.
- 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 tested the mathematical accuracy of the DD&A calculations, including comparing the oil and gas reserve amounts used in the calculations to the Company's reserve reports.

<u>Accounting for Asset Retirement Obligations</u>

Critical Audit Matter Description
At December 31, 2024, the asset retirement obligation ("ARO") balance totaled $13.9 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'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. 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 the Critical Audit Matter was Addressed in the Audit
Our audit procedures related to the evaluation of the accounting for the ARO included the following, among others:

- 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. Our audit procedures included, among others, assessing the significant assumptions and inputs used in the valuation, such as retirement cost estimates and timing of settlement assumptions.
- 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.

Grassi & Co, CPAs, P.C.

GRASSI & CO., CPAs, P.C.

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

Jericho, New York
April 15, 2025

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Thousands of dollars, except share data)

	As of December 31,	
	2024	2023
ASSETS		
Current Assets		
Cash and cash equivalents	$ 2,549	$ 11,061
Accounts receivable, net	24,338	20,301
Prepaid obligations	1,372	376
Other current assets	11	38
Total Current Assets	28,270	31,776
Property and Equipment		
Oil and gas properties at cost	773,330	659,792
Less: Accumulated depletion and depreciation	(479,424)	(406,913)
	293,906	252,879
Field and office equipment at cost	14,643	26,955
Less: Accumulated depreciation	(12,712)	(23,715)
	1,931	3,240
Total Property and Equipment, Net	295,837	256,119
Other assets	515	673
Total Assets	$ 324,622	$ 288,568
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 16,329	$ 15,424
Accrued liabilities	33,092	48,613
Due to related parties	34	80
Current portion of asset retirement and other long-term obligations	200	692
	49,655	64,809
Long-Term Bank Debt	4,000	0
Asset Retirement Obligations	13,799	14,707
Deferred Income Taxes	53,405	47,236
Other Long-Term Obligations	838	866
Total Liabilities	121,697	127,618
Commitments and Contingencies		
Equity		
Common stock, $.10 par value; 2024 and 2023: Authorized: 2,810,000 shares, outstanding 2024: 1,708,470 shares; outstanding 2023: 1,820,100 shares.	281	281
Paid-in capital	7,555	7,555
Retained earnings	261,073	205,669
Treasury stock, at cost; 2024: 1,101,530 shares; 2023: 989,900	(65,984)	(52,555)
Total Stockholders' Equity	202,925	160,950
Total Liabilities and Equity	$ 324,622	$ 288,568

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, 2024	2023
Revenues and other income:		
Oil	$ 193,737	$ 87,906
Natural gas	3,309	7,935
Natural gas liquids	25,996	11,901
Field service	10,852	15,383
Interest and other income, net	184	417
Gain on derivative instruments, net	0	414
Gain on disposition of assets, net	3,718	8,854
	237,796	132,810
Costs and expenses:		
Oil and gas production	47,705	31,892
Production and advalorem taxes	12,148	7,112
Field service	9,112	11,744
Depreciation, depletion and amortization	76,496	30,976
Accretion of discount on asset retirement obligations	733	684
General and administrative	18,883	15,645
Interest	1,546	535
	166,623	98,588
Income before income taxes	71,173	34,222
Income tax provision	15,769	6,119
Net income attributable to common stockholders	$ 55,404	$ 28,103
Net Income per share attributable to Common Stockholders:		
Basic	$ 31.43	$ 15.19
Diluted	$ 21.95	$ 10.77
Weighted average shares Outstanding:		
Basic	1,762,644	1,849,780
Diluted	2,523,581	2,608,786

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)

	Common Stock		Additional			
	Shares Outstanding	Common Stock	Paid-In Capital	Retained Earnings	Treasury Stock	Total Equity
Balance at December 31, 2022	1,901,000	$ 281	$ 7,555	$ 177,566	$ (45,049)	$ 140,353
Purchase of treasury stock	(80,900)	—	—	—	(7,506)	(7,506)
Net income	—	—	—	28,103	—	28,103
Balance at December 31, 2023	1,820,100	$ 281	$ 7,555	$ 205,669	$ (52,555)	$ 160,950
Purchase of treasury stock	(111,630)				(13,429)	(13,429)
Net income				55,404		55,404
Balance at December 31, 2024	1,708,470	$ 281	$ 7,555	$ 261,073	$ (65,984)	$ 202,925

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, 2024	2023
Cash Flows from Operating Activities:		
Net Income	$ 55,404	$ 28,103
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	76,496	30,976
Accretion of discount on asset retirement obligations	733	684
Gain on sale and exchange of assets	(3,718)	(8,854)
Non cash realized gain on derivative instruments, net	0	(980)
Provision for deferred income taxes	6,169	7,268
Changes in assets and liabilities:		
Accounts receivable	(3,777)	(8,492)
Allowance for credit losses	(260)	338
Due from related parties	0	388
Due to related parties	(46)	80
Prepaid obligations	(996)	32,463
Other current assets	27	--
Accounts payable	905	3,973
Accrued liabilities	(15,521)	22,863
Other assets	521	673
Other long-term liabilities	(28)	(468)
Net Cash Provided by Operating Activities	115,909	109,015
Cash Flows from Investing Activities:		
Capital expenditures, including exploration expense	(119,239)	(113,779)
Proceeds from sale of properties and equipment	4,247	8,082
Net Cash (Used in) Investing Activities	(114,992)	(105,697)
Cash Flows from Financing Activities:		
Purchase of stock for treasury	(13,429)	(7,506)
Increase in long-term bank debt and other long-term obligations	110,500	--
Repayment of long-term bank debt and other long-term obligations	(106,500)	(11,294)
Net Cash Used in Financing Activities	(9,429)	(18,800)
Net (Decrease) Increase in Cash and Cash Equivalents	(8,512)	(15,482)
Cash and Cash Equivalents at the Beginning of the Year	11,061	26,543
Cash and Cash Equivalents at the End of the Year	$ 2,549	$ 11,061
Supplemental Disclosures:		
Income taxes paid during the year	$ 113	$ 9,009
Interest paid during the year	$ 1,033	$ 569

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 507 active wells and owns non-operating interests and royalties in approximately 1054 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 stock market under the symbol "PNRG." PERC owns EOWS Midland Company ("EMID") which perform oil and gas field servicing. PERC also owns Prime Operating Company ("POC"), which serves as operator for producing oil and gas properties owned by the Company. 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, and its subsidiaries. All significant intercompany balances and transactions are eliminated in preparing the consolidated financial statements.

Segment Reporting:

The Company operates as one operating segment and one reportable segment which is engaged in the exploration, development, and production of oil, gas, and NGLs in Texas and Oklahoma, from which all of its revenues are derived and expenses incurred. All financial results are reviewed by the Chief Executive Officer ("CEO"), the Company's Chief Operating Decision Maker ("CODM"), on a consolidated basis to evaluate performance of the Company. The single segment constitutes all the consolidated entity and the accompanying consolidated financial statements and the notes to the accompanying consolidated financial statements are representative of such amounts.

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 5, 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.

Cash and cash equivalents:

The Company's cash and cash equivalents include cash on hand and short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

Accounts receivable, net:

The Company's net accounts receivable balance is primarily comprised of oil and gas sales receivables, joint interest receivables and other receivables for which the Company does not require collateral security. The Company's share of oil and gas production is sold to various purchasers and under various joint operating agreements. The Company records allowances for credit losses based on historical collection experience, current and future economic and market conditions, the length of time that the accounts receivables have been outstanding and the financial condition of its purchasers. The Company's credit risk related to collecting accounts receivables is mitigated by using credit and other financial criteria to evaluate the credit standing of the entity obligated to make payment on the accounts receivable, and where appropriate, the Company obtains assurances of payment, such as a guarantee by the parent company of the counterparty, letters of credit or other credit support.

The Company considers forward-looking information to estimate expected credit losses. The Company establishes allowances for credit losses equal to the estimable portions of accounts receivable for which failure to collect is expected to occur. The Company estimates uncollectible amounts for joint interest receivables based on the length of time that the accounts receivables have been outstanding, historical collection experience and current and future economic and market conditions. Allowances for credit losses are recorded as reductions to the carrying values of the receivables included in the Company's consolidated balance sheets and are recorded in expense in the consolidated statements of operations in the accounting periods during which failure to collect an estimable portion is determined to be probable. The Company's allowance for credit losses accounts totaled $414 thousand and $674 thousand as of December 31, 2024 and 2023, respectively.

In June 2016, the FASB issued ASU 2016-13, Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. The standard’s main goal is to improve financial reporting by requiring earlier recognition of credit losses on financing receivables and other financial assets in scope. This guidance is effective for Smaller Reporting Companies for fiscal years beginning after December 15, 2022, including interim periods within those fiscal periods. The Company adopted this standard effective January 1, 2023. The adoption and implementation of this ASU did not have a material impact on the Company’s financial statements.

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, 2024 and 2023, 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:

Field and office equipment is carried at cost. 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.

Leases:

The Company enters into operating leases for its office space in Houston and Midland, Texas. The Company recognizes lease expense on a straight-line basis over the lease term. Lease right-of-use assets and liabilities are initially recorded on the lease commencement date based on the present value of lease payments over the lease term. As the Company's lease contracts do not provide an implicit discount rate, the Company uses its incremental borrowing rate, which is determined based on information available at the commencement date of a lease. 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 as a lease right-of-use asset and liability. See Note 5 for additional information.

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.

Field service income. The majority of the Company's services are performed under Master Service Agreements. The Company recognizes revenue when the products and services are provided to the customer.

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, 2024 and 2023, 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.

New accounting standards.

In November 2023, the FASB issued Accounting Standards Update 2023-07, "Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures," which is effective for fiscal years beginning after December 15, 2023 and interim periods within fiscal years beginning after December 15, 2024 with early adoption permitted. The amendments in this Accounting Standards Update are focused on reportable segment disclosure requirements, primarily related to significant segment expenses, and are required to be applied retrospectively to all prior periods presented in a company's consolidated financial statements.

In December 2023, the FASB issued Accounting Standards Update 2023-09, "Income Taxes (Topic 740): Improvements to Income Tax Disclosures," which is effective for fiscal years beginning after December 15, 2024 with early adoption permitted. The amendments in this Accounting Standards Update are focused on income tax disclosure requirements, primarily related to the income tax rate reconciliation and income taxes paid, with prospective application to a company's consolidated financial statements recommended.

Recently Adopted Accounting Standards:

In November 2023, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update (“ASU”) No. 2023-07, Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures, which requires significant segment disclosures on an annual and interim basis. Additionally, it requires disclosure of the title and position of the Chief Operating Decision Maker (“CODM”) and requires a public entity that has a single reportable segment to provide all disclosures required by the amendments in this ASU and all existing segment disclosures in Topic 280. The new standard is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024, with early adoption permitted. The adoption of this ASU only impacted disclosures with no impact on the Company’s consolidated financial statements. The Company adopted this ASU effective December 31, 2024; see Segment Information above.

Recently Issued Accounting Standards:

In November 2024, the FASB issued ASU No. 2024-03, Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses. This standard requires that public business entities disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods. This ASU is effective for annual reporting periods beginning after December 15, 2026, and interim periods within annual reporting periods beginning after December 15, 2027. Early adoption is permitted. The Company is currently evaluating this ASU to determine its impact on the Company’s financial statements and related disclosures.

2. Acquisitions and Dispositions

2024 Transactions:

In the first quarter of 2024, the Company sold 48 net acres in Lea County, New Mexico, along with minor working interest in 23 non-operated wells, receiving gross proceeds of $375,600, and in the second quarter of 2024, sold an additional 12 net acres in Lea County for proceeds of $150,600 and sold 2.29 surface acres in Odessa, Texas for $68,036. Also in the second quarter of 2024, we farmed out certain acreage in east Texas for $55,000.

In the third quarter of 2024, acreage transactions included the acquisition of 100.27 net acres in Reagan County, Texas for a purchase price of $1,109,785 and another purchase of 281 net acres in Reagan County for $2,774,025. Also in the second quarter of 2024, we sold 7.8 surface acres in Midland County, Texas for proceeds of $427,760 and sold 44.58 net acres of leasehold interest in Roger Mills County Oklahoma for proceeds of $89,159. In New Mexico, we sold our remaining working interests in seven properties in Lea and Eddy Counties for $220,000. Effective September 1, 2024, the Company sold its interest in Eastern Oil Well Service Company, a south Texas well-servicing business, for net proceeds of $2,800,000, recognizing a gain on sale of $1,921,000.

2023 Transactions:

In the first quarter of 2023, the Company sold 7.8 surface acres in Midland County, Texas receiving gross proceeds of $436,050 and recognizing a gain of $47,000.

In the second quarter of 2023, the Company acquired 55 net acres in the South Stiles area of Reagan County, Texas for $605,000, and in a separate agreement also in Reagan County, the Company sold 320 non-core acres for proceeds of $6,000,000. In addition, the Company sold 36.51% interest in one well in Midland County, Texas for proceeds of $60,000.

In the third quarter of 2023, the Company sold a non-core 38.25-acre leasehold tract in Martin County, Texas for proceeds of $899,000 and sold 3 surface acres in Liberty County, Texas for net proceeds of $37,053. Also in the third quarter, in various counties of Oklahoma, the Company divested its interest in 39 wells, reducing its future plugging liability by approximately $1.5 million. Effective July 1, 2023, the Company acquired the operations of 36 wells from DE Permian and 50% of DE Permian's original ownership in such wells. In addition, in Reagan County, Texas, the Company acquired 114.52 net acres from DE Permian for $1,700,853 and assigned to them 203.23 net acres.

In the fourth quarter of 2023, the Company sold 136 surface acres in Oklahoma for net proceeds of $306,000 and in Midland Texas sold 9.35 net acres for proceeds of $280,423, recognizing a gain on sale of $1,921,000.

3. Additional Balance Sheet Information

Accounts receivable, net at December 31, 2024 and 2023 consisted of the following:

(Thousands of dollars)	December 31, 2024	December 31, 2023
Joint interest billings	$ 2,413	$ 2,560
Trade receivables	958	2,345
Oil and gas sales	21,211	14,457
Taxes	0	1,458
Other	170	155
	24,752	20,975
Less: Allowance for credit losses	(414)	(674)
Total	$ 24,338	$ 20,301

Accounts payable at December 31, 2024 and 2023 consisted of the following:

(Thousands of dollars)	December 31, 2024	December 31, 2023
Trade	$ 12,038	$ 9,847
Royalty and other owners	3,607	4,405
Partner advances	511	946
Other	173	226
Total	$ 16,329	$ 15,424

Accrued liabilities at December 31, 2024 and 2023 consisted of the following:

(Thousands of dollars)	December 31, 2024	December 31, 2023
Compensation and related expenses	$ 10,668	$ 10,324
Property costs	7,578	33,264
Taxes	9,524	929
Lease operating costs	4,263	3,898
Other	1,059	198
Total	$ 33,092	$ 48,613

4. Long-Term Debt

Bank Debt:

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.

Effective January 20, 2023, in lieu of a formal amendment, a borrowing base letter authorized by all lenders and the Company 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.

Effective July 24, 2023, in lieu of a formal amendment, a borrowing base letter authorized by all lenders and the Company of the 2022 Credit Agreement resulted in an adjustment to increase the amount of the Borrowing Base available from $60 million to $65 million until such time as the next redetermination date as required by the agreement.

As of December 31, 2023, the borrowing base was $65 million and the Company had no outstanding borrowings under the Credit Facility. The prime rate in effect for December 2023 was 8.50%, and if the Company had loans designated as prime rate loans, it would have been subject to an effective rate of prime plus a borrowing base utilization percentage between 2.25% and 3.25%, depending on the outstanding borrowings of effective rates between 10.75% and 11.75%.

Effective February 9, 2024, the Company and its lenders entered into the Second Amendment to the 2022 Credit Agreement. This amendment included an increase of the Borrowing Base from $65 million to $85

Effective July 29, 2024, the Company and its lenders entered into the Third Amendment to the 2022 Credit Agreement, increasing the Borrowing Base from $85,000,000 to $115,000,000.

Effective December 20, 2024, the Company and its lenders entered into the Fourth Amendment to the 2022 Credit Agreement, reaffirming the credit agreement at $115,000,000. The Borrowing base will remain in effect until the next Redetermination Date, June 2025, or the date the Borrowing Base is next adjusted in accordance with the Credit Agreement. As of December 31, 2024, the Company had $4 million in outstanding borrowings and $111 million in availability. The prime rate in effect for December 2024, was 7.50%. The $4 million in outstanding borrowings was considered prime rate borrowings, and were subject to utilization percentage of 2.25%. The effective rate for this borrowing balance at December 31, 2024, was 9.75%.

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. 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 8.97%. 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, 2024 and 2023 were $739 thousand and $700 thousand, respectively. Cash payments included in the operating lease cost for years ended December 31, 2024 and 2023 were $792 thousand and $739 thousand, respectively. The weighted-average remaining operating lease terms for the years ended December 31, 2024 and 2023 were 3 months and 11 months, respectively. As of December 2024, the Company had certain leases for office space in Texas which included future payments of $149 thousand in 2025. Rent expense for office space for the years ended December 31, 2024 and 2023 was $893,000 and $767,000, respectively.

On February 16, 2025, the Company entered into a twelve-month lease extension agreement, effective March 1, 2025, with the landlord of the Company's Houston office. On March 31, 2025, the Company entered into two additional leases for office space for Prime Operating's Midland and EOWS Midland Company's offices. These leases were effective April 1, 2025 and were for two-year and three-year terms, respectively. Additional rent expense, combined for the three new leases for the years ended December 31, 2025, 2026, 2027 and 2028, will be $671,000, $290,000, $127,000, and $27,000 respectively.

The payment schedule for the Company's operating lease obligations as of December 31, 2024 is as follows:

(Thousands of dollars)	Operating Leases
2025	149
Total undiscounted lease payments	$ 149
Less: Amount associated with discounting	(17)
Total net operating lease liabilities	$ 132
Less: Current portion included in Current portion of Asset Retirement and Other Long-Term Obligations	132
Non-current portion included in Other Long-Term Obligations	$ 0

Asset Retirement Obligation:

A reconciliation of the liability for plugging and abandonment costs for the years ended December 31, 2024 and 2023 is as follows:

	Years Ended December 31,	
(Thousands of dollars)	**2024**	**2023**
Asset retirement obligation at beginning of period	$ 15,153	$ 15,443
Net wells placed on production	210	254
Liabilities settled	(947)	(2,706)
Dispositions	(350)	(1,161)
Accretion expense	733	684
Revisions in estimated liabilities	(932)	2,639
Asset retirement obligation at end of period	$ 13,867	$ 15,153
Less: Current portion included in Current portion of asset retirement and other long-term obligations	68	446
Long-term Asset Retirement Obligations included in Asset Retirement Obligations	$ 13,799	$ 14,707

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, 2024 and 2023, 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, 2024 and 2023 are as follows:

	Years Ended December 31,	
(Thousands of dollars)	**2024**	**2023**
Current:		
Federal	$ 8,545	$ (891)
State	1,055	(258)
Total current	9,600	(1,149)
Deferred:		
Federal	6,080	6,544
State	89	724
Total deferred	6,169	7,268
Total income tax provision	$ 15,769	$ 6,119

The components of net deferred tax assets and liabilities are as follows:

	At December 31,	
(Thousands of dollars)	**2024**	**2023**
Deferred Tax Assets:		
Accrued liabilities	$ 279	$ 349
Allowance for credit losses	93	154
Partnership basis difference	114	106
State Net operating loss carry-forwards	212	278
Total deferred tax assets	698	887
Deferred Tax Liabilities:		
Depletion and depreciation	54,103	48,123
Total deferred tax liabilities	54,103	48,123
Net deferred tax liabilities	$ 53,405	$ 47,236

The total provision for income taxes for the years ended December 31, 2024 and 2023 varies from the federal statutory tax rate as a result of the following:

	Years Ended December 31,	
(Thousands of dollars)	**2024**	**2023**
Expected tax expense	$ 14,946	$ 7,187
Permanent differences	880	221
State income tax, net of federal benefit	834	204
Provision to return adjustment	(679)	(1,534)
Tax credits	(599)	0
Other, net	387	41
Total income tax provision	$ 15,769	$ 6,119

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 2025 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 2021 through 2023 remain open for examination by the relevant taxing authorities.

Enactment of the Inflation Reduction Act of 2022.

On August 16, 2022, former 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 is imposed on certain adjusted financial statement income of "applicable corporations," which became 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 value of share repurchases subject to the excise tax is reduced by the fair market value of any shares issued during the tax year, including the fair market value of any shares issued or provided to employees or specified affiliates. During the year ended December 31, 2023 and 2024, the Company recorded $74 thousand and $133 thousand respectively, related to the IRA excise tax payable on share repurchases.

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 2024 and 2023.

	2024	2023
Oil:		
DE IV Operating, LLC.	44%	14%
Civitas Resources Inc.	20%	20%
APA Corporation.	12%	22%
Plains All American	6%	19%
Natural gas and liquids:		
DE IV Operating, LLC.	30%	0%
Civitas Resources Inc.	22%	20%
APA Corporation.	19%	17%

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 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 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 would not be provided. As of the balance sheet reporting dates of December 31, 2024 and 2023, the Company had no active 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 statements of income for the years ended December 2024 and 2023:

		Amount of gain/loss recognized in income	
(Thousands of dollars)	**Location of gain/loss recognized in income**	**2024**	**2023**
Derivatives not designated as cash-flow hedge instruments:			
Natural gas commodity contracts	Gain on derivative instruments, net	0	235
Crude oil commodity contracts	Gain on derivative instruments, net	0	179
		$ 0	$ 414

11. Related Party Transactions

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 $349,554 and $362,756 were made in 2024 and 2023, 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,					
	2024			2023		
	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	$ 55,404	1,762,644	$ 31.43	$ 28,103	1,849,780	$ 15.19
Effect of dilutive securities:						
Options		760,937		—	759,006	
Diluted	$ 55,404	2,523,581	$ 21.95	$ 28,103	2,608,786	$ 10.77

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

(Unaudited)

(Thousands of dollars)	As of December 31, 2024	As of December 31, 2023
Proved Developed oil and gas properties	$ 773,330	$ 659,792
Proved Undeveloped oil and gas properties	—	—
Total Capitalized Costs	773,330	659,792
Accumulated depreciation, depletion and valuation allowance	(479,424)	(406,913)
Net Capitalized Costs	$ 293,906	$ 252,879

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

(Unaudited)

(Thousands of dollars)	Years Ended December 31, 2024	Years Ended December 31, 2023
Development Costs	$ 117,424	$ 110,700

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

(Unaudited)

(Thousands of dollars)	As of December 31, 2024	As of December 31, 2023
Future cash inflows	$ 981,343	$ 1,219,605
Future production costs	(374,816)	(437,408)
Future development costs	(105,811)	(213,823)
Future income tax expenses	(105,150)	(119,359)
Future Net Cash Flows	395,566	449,015
10% annual discount for estimated timing of cash flows	(122,521)	(170,967)
Standardized Measure of Discounted Future Net Cash Flows	$ 273,045	$ 278,048

See accompanying Notes to 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 2024 and 2023:

	Years Ended December 31,	
(Thousands of dollars)	**2024**	**2023**
Sales of oil and gas produced, net of production costs	$ (223,042)	$ (107,742)
Net changes in prices and production costs	(40,024)	(98,132)
Extensions, discoveries and improved recovery	24,848	178,960
Revisions of previous quantity estimates	(39,149)	(3,877)
Net change in development costs	70,002	66,552
Reserves sold	(1,371)	(398)
Accretion of discount	27,805	24,454
Net change in income taxes	8,896	4,532
Changes in production rates (timing) and other	167,032	(30,836)
Net change	(5,003)	33,512
Standardized measure of discounted future net cash flow:		
Beginning of year	278,048	244,536
End of year	$ 273,045	$ 278,048

See accompanying Notes to Supplementary Information

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

RESERVE QUANTITY INFORMATION
Years Ended December 31, 2024 and 2023

(Unaudited)

	As of December 31,					
	2024			2023		
	Oil (MBbls)	NGL's (MBbls)	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)
Proved Developed Reserves:						
Beginning of year	5,757	3,676	24,749	4,143	2,497	22,277
Extensions, discoveries and improved recovery	186	132	859	843	467	2,391
Revisions of previous estimates	(745)	(385)	(983)	(1,101)	(515)	(4,796)
Converted from undeveloped reserves	4,854	4,509	20,791	3,028	1,833	9,030
Production	(2,556)	(1,284)	(7,766)	(1,144)	(606)	(4,127)
End of year	7,443	6,597	37,489	5,757	3,676	24,749
Proved Undeveloped Reserves:						
Beginning of year	6,254	5,156	24,470	3,028	1,833	9,030
Extensions, discoveries and improved recovery	3,166	1,670	8,327	6,254	5,156	24,470
Revisions of previous estimates	(1,400)	(647)	(3,680)	—	—	—
Converted to developed reserves	(4,854)	(4,509)	(20,791)	(3,028)	(1,833)	(9,030)
Reserves Sold	—	—	—	—	—	—
End of year	3,166	1,670	8,326	6,254	5,156	24,470
Total Proved Reserves at the End of the Year	10,609	8,267	45,815	12,011	8,832	49,219

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES
Years Ended December 31, 2024 and 2023

(Unaudited)

	Years Ended December 31,	
(Thousands of dollars)	2024	2023
Revenue:		
Oil and gas sales	$ 223,042	$ 107,742
Costs and Expenses:		
Lease operating expenses	59,853	39,004
Depreciation, depletion and accretion	77,229	31,660
Income tax expense	16,884	5,797
Total Costs and Expenses	153,966	76,461
Results of Operations from Producing Activities (excluding corporate overhead and interest costs)	$ 69,076	$ 31,281

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 2024 and 2023 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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Corporate Information

Auditors

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

Commercial Bankers

Citibank, N.A.
Fifth Third Bank
U.S. Bank National Association
West Texas National Bank
Independent Bank

Transfer Agent

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

NASDAQ Symbol:

PNRG

Annual Meeting

June 5, 2025 at 9:00 a.m. CDT
at the offices of the Company
9821 Katy Freeway
Houston, Texas 77024

Executive Offices

9821 Katy Freeway,
Houston, TX 77024

Operating Offices:

Prime Operating Company
Houston,Texas
Midland, Texas
Oklahoma City, OK

PrimeEnergy Management Corporation
Houston, Texas

Field Offices

Prime Opearating Company
Garvin, OK

EOWS Midland Company
Midland, Texas

10-K Information

The Company's 2024 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

PrimeEnergy Resources Corporation
2024 Annual Report