CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

The information in this Form 10-Q contains statements which, to the extent they are not statements of historical or present fact, constitute "forward-looking statements" under the securities laws. These forward-looking statements are intended to provide management's current expectations or plans for our future operating and financial performance, based on assumptions currently believed to be valid. Forward-looking statements can be identified by the use of words such as "believe," "expect," "expectations," "plans," "strategy," "prospects," "estimate," "project," "target," "anticipate," "will," "should," "see," "guidance," "outlook," "confident" and other words of similar meaning in connection with a discussion of future operating or financial performance. Forward-looking statements may include, among other things, statements relating to future earnings, cash flow, results of operations, uses of cash, tax rates and other measures of financial performance or potential future plans, strategies or transactions of Vitesse, and other statements that are not historical facts. Forward-looking statements are not guarantees of future results and conditions, but rather are subject to numerous assumptions, risks, and uncertainties that may cause actual future results to be materially different from those contemplated, projected, estimated, or budgeted. Such assumptions, risks, uncertainties and other factors include, but are not limited to, the following:

- the timing and extent of changes in oil and natural gas prices;
- our ability to successfully implement our business plan;
- the Lucero Acquisition (as defined herein) may not be accretive, and may be dilutive, to our earnings per share, which may negatively affect the market price of our common stock;
- the ultimate timing, outcome, and results of integrating and executing on Lucero's operations;
- the pace of our operators' drilling and completion activity on our properties, including in connection with refrac programs and extended length three-mile and four-mile lateral wells;
- our operators' ability to complete projects on time and on budget;
- uncertainties about estimates of reserves, identification of drilling locations and the ability to add reserves in the future;
- our ability to complete acquisitions;
- actions taken by third-party operators, processors, transporters and gatherers;
- extreme weather events, natural disasters, fluctuating regional and global weather conditions or patterns, pandemic, war (such as conflict in the Middle East and the ongoing military conflict in Ukraine), financial or political instability, casualty losses and other matters beyond our control;
- changes in general economic conditions, including central bank policy actions, inflation and changes in US trade policy and the imposition of and changes in tariffs;
- our ability to achieve the benefits that we expect to achieve as an independent publicly traded company;
- the qualification of the Distribution and certain related transactions as tax-free under the Code;
- infrastructure constraints and related factors affecting our properties;
- competitive conditions in our industry;
- the effects of existing and future laws and governmental regulations, including the effects of a prolonged U.S. government shutdown;
- the availability and price of oil and natural gas to the consumer compared to the price of alternative and competing fuels;
- operating hazards and other risks incidental to gathering, storing and transporting oil and natural gas;
- restrictions in our Revolving Credit Facility;
- interest rates;
- the effects of future litigation;
- cyber-related risks;
- changes in insurance markets impacting costs and the level and types of coverage available;
- financial, regulatory, and political risks associated with societal responses to climate change;
- energy efficiency and technology trends;
- changes in the availability and cost of capital;
- large customer defaults; and
- labor relations.

The above list of factors is not exhaustive. For additional information on identifying factors that may cause actual results to vary materially from those stated in forward-looking statements, see the discussion under the section Part II, Item 1A Risk Factors in this Form 10-Q and Part I, Item 1A Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2024, filed with the SEC on March 12, 2025.

Reserve engineering is a process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact way. The accuracy of any reserve estimates depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered.

Any forward-looking statements, express or implied, included in this Form 10-Q are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue. Any forward-looking statement that we make in this Form 10-Q speaks only as of the date on which it was made. Except as otherwise required by applicable law, we expressly disclaim any obligation to, update or alter our forward-looking statements, whether as a result of new information, subsequent events or otherwise.

GLOSSARY

In this Form 10-Q, unless the context otherwise requires:

- "Amended and Restated Bylaws" refers to the bylaws of Vitesse effective as of January 13, 2023;
- "Amended and Restated Certificate of Incorporation" refers to the certificate of incorporation of Vitesse effective as of January 12, 2023;
- "Basin" refers to a large natural depression on the earth's surface in which sediments generally brought by water accumulate;
- "Board" refers to our board of directors;
- "Bbl" refers to one stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or NGLs;
- "Boe" refers to barrels of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil;
- "Boe/d" refers to one Boe per day;
- "Btu" refers to a British thermal unit, which is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit;
- "Code" refers to the United States Internal Revenue Code of 1986, as amended;
- "completion" refers to the process of preparing an oil and natural gas wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to optimize production of oil, natural gas and/or NGLs;
- "condensate" refers to a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature;
- "differential" refers to an adjustment to the price of oil or natural gas from an established index price to reflect differences in the quality and/or location of oil or natural gas;
- "Distribution" refers to the transaction on January 13, 2023 in which Jefferies distributed to its shareholders outstanding shares of our common stock held by Jefferies;
- "dry hole" refers to a well found to be incapable of producing oil and natural gas in sufficient quantities to justify completion;
- "EIA" refers to the Energy Information Agency;
- "Exchange Act" refers to the Securities Exchange Act of 1934, as amended;
- "GAAP" refers to accounting principles generally accepted in the United States;
- "gross acres" refers to the total acres in which a working interest is owned;
- "gross wells" refers to the total wells in which a working interest is owned;
- "Jefferies" or "JFG" refers to Jefferies Financial Group Inc. and its consolidated subsidiaries other than, for all periods following the Spin-Off, Vitesse, unless the context requires otherwise;
- "LTIP" refers to the Company's long term incentive plan;
- "Lucero" refers to Lucero Energy Corp., a corporation existing under the Alberta Business Corporations Act except subsequent to April 24, 2025 when it refers to Lucero Energy ULC and PetroShale (US), Inc.;
- "Lucero Acquisition" refers to the strategic business combination transaction that closed on March 7, 2025 whereby Vitesse acquired all of the issued and outstanding Lucero common shares pursuant to the Lucero Plan of Arrangement, with Lucero becoming a wholly owned subsidiary of Vitesse;
- "Lucero Arrangement Agreement" refers to that certain Lucero Arrangement Agreement, dated December 15, 2024, between Vitesse and Lucero, a copy of which is attached to the Current Report on Form 8-K filed with the SEC on December 19, 2024;
- "Lucero Plan of Arrangement" refers to that certain Plan of Arrangement substantially in the form attached as Exhibit B to the Lucero Arrangement Agreement, and any amendments or variations thereto made in accordance with the Lucero Arrangement Agreement and the Plan of Arrangement or upon the direction of the Alberta Court, in the Final Order;
- "MBbls" refers to one thousand barrels of oil or NGLs;
- "MBoe" refers to one thousand barrels of oil equivalent;
- "Mcf" refers to one thousand cubic feet of natural gas;
- "MMBoe" refers to one million barrels of oil equivalent;
- "MMBtu" refers to one million British thermal units;
- "MMcf" refers to one million cubic feet of natural gas;
- "net acres" refers to the sum of the fractional working interests owned in gross acres (e.g., a 10% working interest in a lease covering 1,280 gross acres is equivalent to 128 net acres);
- "net wells" refers to wells that are deemed to exist when the sum of fractional ownership working interests in gross wells equals one;
- "NGLs" refer to natural gas liquids;

- “NYMEX” refers to the New York Mercantile Exchange;
- “OPEC” refers to the Organization of Petroleum Exporting Countries;
- “PDP” or “proved developed producing” refers to proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods;
- “PDNP” or “proved developed non-producing” refers to proved reserves that are developed behind pipe and are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production;
- “possible reserves” refers to the additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves;
- “Pre-Spin-Off Transactions” refers to the series of transactions, including Vitesse’s acquisitions of Vitesse Energy and Vitesse Oil, consummated immediately prior to the Distribution;
- “probable reserves” refers to the additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered;
- “productive well” refers to a well that is found to be capable of producing oil and natural gas in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes;
- “proved developed reserves” refers to proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of new equipment or operating methods is relatively minor compared to the cost of a new well;
- “proved reserves” refers to the quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time;
- “PUD” or “proved undeveloped” refers to proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years from the date that such undrilled location was initially classified as proved undeveloped unless specific circumstances justify a longer time. Under no circumstances shall estimates of 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;
- “PSU” refers to Performance Stock Units under the LTIP;
- “reserves” refers to estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project;
- “Revolving Credit Facility” refers to Vitesse’s Second Amended and Restated Credit Agreement, as amended from time to time, among Vitesse, as borrower, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto, dated as of January 13, 2023;
- “RSU” refers to Restricted Stock Units under the LTIP;
- “SEC” refers to the Securities and Exchange Commission;
- “Securities Act” refers to Securities Act of 1933, as amended;
- “SOFR” refers to the Secured Overnight Financing Rate;
- “Spin-Off” refers to our separation on January 13, 2023 from Jefferies and the creation of an independent, publicly traded company, Vitesse, through (1) the Pre-Spin-Off Transactions and (2) the Distribution;
- “Stock Repurchase Program” refers to the stock repurchase program approved by the Board in February 2023 authorizing the repurchase of up to $60 million of the Company’s common stock;
- “Tax Matters Agreement” refers to the tax matters agreement entered into between Jefferies and the Company on January 13, 2023;
- “Two-stream basis” refers to the reporting of production or reserve volumes of oil and wet natural gas, where the NGLs have not been removed from the natural gas stream, and the economic value of the NGLs is included in the wellhead natural gas price;
- “Vitesse,” “we,” “our,” “us” and the “Company” (1) when used in regard to events prior to the Spin-Off, refer to Vitesse Energy and do not give effect to the consummation of the Pre-Spin-Off Transactions, and (2) when used in regard to

events subsequent to the Spin-Off or future tense, refer to Vitesse Energy, Inc. and its consolidated subsidiaries and give effect to the consummation of the Pre-Spin-Off Transactions, in each case unless the context requires otherwise;

- "Vitesse Energy" and the "Predecessor" refer to Vitesse Energy, LLC and its consolidated subsidiaries;
- "Vitesse Oil" refers to Vitesse Oil, LLC;
- "WTI" refers to West Texas Intermediate.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

You should read the following discussion of our results of operations and financial condition together with our Condensed Consolidated Financial Statements and the notes thereto included under Part I – Financial Information. This discussion contains forward-looking statements that involve risks and uncertainties. The forward-looking statements are not historical facts, but rather are based on current expectations, estimates, assumptions and projections about the oil and natural gas industry and our business and financial results. Our actual results could differ materially from the results contemplated by these forward-looking statements due to a number of factors, including those discussed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2024 in the section entitled Part I, Item 1A Risk Factors and in this Quarterly Report on Form 10-Q in the sections entitled Part II, Item 1A Risk Factors and "Cautionary Statement Concerning Forward-Looking Statements."

As further described in Note 3 ("Oil and Gas Properties") to the Condensed Consolidated Financial Statements set forth in Part I, Item 1 of this Quarterly Report on Form 10-Q, we completed the Lucero Acquisition on March 7, 2025. The financial information presented herein (i) excludes the results of Lucero and its subsidiaries for periods prior to March 7, 2025 and (ii) includes the results of Lucero and its subsidiaries for periods on or after March 7, 2025.

Executive Overview

Our business strategy is focused on creating long-term stockholder value through the profitable acquisition, development and production of oil and natural gas assets that provide an attractive return on invested capital, while maintaining a strong balance sheet and distributing a meaningful dividend to our stockholders. We invest in working and mineral interests in oil and natural gas properties with our core area of focus currently in the Bakken and Three Forks formations of the Williston Basin of North Dakota and Montana. We also have interests in wells in the Denver-Julesburg Basin located in Colorado and Wyoming and the Powder River Basin located in Wyoming. As of September 30, 2025, we had a working interest in 6,326 gross (225.7 net) productive wells and 268 gross (5.6 net) wells that were being drilled or completed, and an additional 377 gross (15.2 net) wells that had been permitted for development by our operators. In addition, we had a royalty only interest in 1,286 gross (3.2 net) productive wells.

Our financial and operating performance for the three months ended September 30, 2025 included the following:

- Paid quarterly dividend of $0.5625 per share to our common stockholders.
- Production of 18,163 BOE/day with 65% of production from oil.
- Total revenue of $67.4 million.
- Net loss of $1.3 million.
- Cash flows from operations of $49.4 million.
- Invested $31.8 million in capital development and acquisitions.
- Total debt of $114.0 million at September 30, 2025.

Industry Trends Impacting Our Business

Commodity prices are a significant factor impacting our earnings, operating cash flows and our acquisition and divestiture strategy, as well as the decisions of us and our operators in conducting operations. During the last several years, prices for oil and natural gas have experienced periodic downturns and sustained volatility, impacted by general economic and political conditions, the ongoing military conflict between Russia and Ukraine, conflict in the Middle East, supply chain constraints, elevated interest rates and costs of capital, and changes in production by OPEC and its key member, Saudi Arabia, and certain other non-OPEC oil-producing countries.

As a result of such commodity price volatility, which we expect to continue throughout 2025, our earnings and operating cash flows can vary substantially. While we do hedge a substantial portion of our production, we are still significantly subject to movements in commodity prices. Such volatility can make it difficult to predict future effects on our financial results and the decisions of our operators. Factors that we expect will continue to impact commodity prices include product demand connected with global economic conditions, inflationary factors, industry production and inventory levels, the United States Department of Energy's planned repurchases (or possible releases) of oil from the strategic petroleum reserve, technology advancements, production quotas or other actions imposed by OPEC and other oil-producing countries, the imposition of and changes in tariffs and other controls on imports and exports and resulting consequences of such, actions of regulators, and regional supply interruptions or fears thereof that may be caused by military conflicts, civil unrest or political uncertainty, including a prolonged U.S. government shutdown. Any of the foregoing can have a substantial impact on the prices of oil and natural gas, which in turn impacts our decisions and the decision of our operators to drill and extract resources.

Source of Our Revenues

We derive our revenues from the sale of oil and natural gas produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, oil quality, Btu content and transportation costs to market. We use derivative instruments to hedge future sales prices on a substantial, but varying, portion of our oil and natural gas production. We expect our derivative activities will help us achieve more predictable cash flows and reduce our exposure to downward price fluctuations. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also mitigates the effects of declining price movements.

Principal Components of Our Cost Structure

Commodity price differentials. The price differential between our wellhead price for oil and the WTI benchmark price is primarily driven by the cost to transport oil via pipeline, train or truck to refineries. The price differential between our wellhead price for natural gas and the NYMEX benchmark price is primarily driven by Btu content along with gathering, processing and transportation costs.

Commodity derivative gain, net. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the prices of oil and gas. Gain (loss) on commodity derivatives, net is comprised of (1) cash gains and losses we recognize on settled commodity derivatives during the period, and (2) non-cash mark-to-market gains and losses we incur on commodity derivative instruments outstanding at period-end.

Lease operating expenses. Lease operating expenses are costs incurred to bring oil and natural gas out of the ground and to market, together with the costs incurred to maintain our producing properties. Such costs include field personnel compensation, saltwater disposal, utilities, maintenance, repairs and servicing expenses related to our oil and natural gas properties.

Production taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

DD&A. DD&A includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas properties. As a successful efforts company, costs associated with the acquisition, drilling, and equipping of successful exploratory wells and costs of successful and unsuccessful development wells are capitalized. Accretion expense relates to the passage of time of our asset retirement obligations.

General and administrative expenses. General and administrative expenses include overhead, including payroll and benefits for our staff, costs of maintaining our headquarters, costs of managing our acquisition and development operations, franchise taxes, audit and other professional fees and legal compliance. During the nine months ended September 30, 2025, general and administrative expenses included non-recurring costs related to the Lucero Acquisition and an offset for reimbursement of past legal expenses as a result of the settlement discussed in Note 9 (“Commitments and Contingencies”) to the Condensed Consolidated Financial Statements.

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Revolving Credit Facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We do not capitalize any portion of the interest paid on applicable borrowings. We include the amortization of deferred financing costs, commitment fees and annual agency fees as interest expense.

Impairment expense. Under the successful efforts method of accounting, we review our oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Whenever we conclude the carrying value may not be recoverable, we estimate the expected undiscounted future net cash flows of our oil and natural gas properties using proved and risked probable and possible reserves based on our development plans and best estimate of future production, commodity pricing, reserve risking, gathering, processing and transportation deductions, production tax rates, lease operating expenses and future development costs. We compare such undiscounted future net cash flows to the carrying amount of the oil and natural gas properties in each depletion pool to determine if the carrying amount is recoverable. If the undiscounted future net cash flows exceed the carrying amount of the aggregated oil and natural gas properties, no impairment is recorded. If the carrying amount of the oil and natural gas properties exceeds the undiscounted future net cash flows, we will record an impairment expense to reduce the carrying value to fair value as of the balance sheet date. The factors used to determine fair value may include, but are not limited to, recent sales prices of comparable properties, indications from marketing activities, the present value of future revenues, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the projected cash flows. There were no proved oil and gas property impairments during the three and nine months ended September 30, 2025 and 2024.

Income tax expense. Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP, which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. 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.

Selected Factors That Affect Our Operating Results

Our revenues, cash flows from operations and future growth depend substantially upon:

- the timing and success of our drilling and production activities and those of our operating partners;
- the prices and the supply and demand for oil, natural gas and NGLs;
- the quantity of oil and natural gas production from the wells in which we participate;
- the realized gains and losses on our derivative instruments;
- our ability to continue to identify and acquire producing properties, high-quality acreage and drilling opportunities; and
- the level of our operating expenses.

In addition to the factors that affect companies in our industry generally, the location of substantially all of our acreage and wells in the Williston, Denver-Julesburg and Powder River Basins subjects our operating results to factors specific to these regions. These factors include the potential adverse impact of weather on drilling, production and transportation activities, particularly during the winter and spring months, as well as infrastructure limitations, transportation capacity, regulatory matters and other factors that may specifically affect one or more of these regions.

Market Conditions

The price of oil can vary depending on the market in which it is sold and the means of transportation used to transport the oil to market, particularly in the Williston Basin where a substantial majority of our revenues are derived. Additional pipeline infrastructure has increased takeaway capacity in the Williston Basin which has improved wellhead values in the region.

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Because our oil and gas revenues are heavily weighted toward oil, we are more significantly impacted by changes in oil prices than by changes in the price of natural gas. Worldwide supply in terms of output, especially production from properties within the United States, the production quotas set by OPEC and certain other oil-producing countries, the conflicts in Ukraine and in the Middle East and the strength of the U.S. dollar can adversely impact oil prices.

Historically, commodity prices have been volatile and we expect the volatility to continue in the future. Future oil prices will be impacted by varying oil supply and demand both regionally and worldwide.

Prices for various quantities of oil, natural gas and NGLs significantly impact our revenues and cash flows. The following table lists average NYMEX prices for oil and natural gas for the periods presented.

	THREE MONTHS ENDED SEPTEMBER 30,	
Average Daily Prices [1]	**2025**	**2024**
Oil (per Bbl)	$ 64.84	$ 75.26
Natural Gas (per MMBtu)	3.03	2.11
	NINE MONTHS ENDED SEPTEMBER 30,	
Average Daily Prices [1]	**2025**	**2024**
Oil (per Bbl)	$ 66.50	$ 77.53
Natural Gas (per MMBtu)	3.45	2.11

(1) Based on average daily NYMEX WTI and Henry Hub Spot closing prices reported by FactSet and the EIA, respectively.

The average third quarter 2025 NYMEX oil price was $64.84 per barrel or 14% lower than the average oil price per barrel in the third quarter of 2024. Our settled derivatives increased our realized oil price per barrel by $2.98 and $1.77 in the third quarter of 2025 and 2024, respectively. Our average third quarter 2025 realized oil price per barrel after reflecting settled derivatives was $62.71 compared to $71.20 during the same period in 2024.

The average third quarter 2025 NYMEX natural gas price was $3.03 per MMBtu, or 44% higher than the average NYMEX price per MMBtu in the third quarter of 2024. In the third quarter 2025, our settled derivatives increased our realized natural gas price by $0.29 per Mcf, bringing our realized natural gas price after reflecting settled derivatives to $1.14 per Mcf. In the third quarter 2024, we had no natural gas price derivatives in place and our realized natural gas price was $0.90 per Mcf.

The average year-to-date 2025 NYMEX oil price was $66.50 per barrel or 14% lower than the 2024 average year-to-date oil price per barrel. Our settled derivatives increased our average year-to-date 2025 and 2024 realized oil price per barrel by $2.94 and $0.50, respectively. Our average year-to-date 2025 realized oil price per barrel after reflecting settled derivatives was $63.90 compared to $72.12 during the same period in 2024.

The average year-to-date 2025 NYMEX natural gas price was $3.45 per MMBtu, or 64% higher than the 2024 average year-to-date price per MMBtu. During the nine months ended September 30, 2025, our settled derivatives increased our realized natural gas price by $0.11 per Mcf, bringing our realized natural gas price after reflecting settled derivatives to $2.71 per Mcf. During the nine months ended September 30, 2024, we had no natural gas price derivatives in place and our realized natural gas price was $1.29 per Mcf.

We employ a hedging program that partially mitigates the risk associated with fluctuations in commodity prices. For detailed information on our commodity hedging program, see Part I, Item 3 Quantitative and Qualitative Disclosures about Market Risk and Note 6 ("Derivative Instruments") to the Condensed Consolidated Financial Statements.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells can vary significantly, driven in part by volatility in commodity prices that can substantially impact the level of drilling activity. Generally, higher oil prices have led to increased drilling activity, with the increased demand for drilling and completion services driving these costs higher. Lower oil prices have generally had the opposite effect. In addition, individual components of the cost can vary depending on numerous factors such as the length of the horizontal lateral, the number of fracture stimulation stages, and the type and amount of proppant.

Results of Operations

Three Months Ended September 30, 2025 Compared with Three Months Ended September 30, 2024

The following table sets forth selected financial and operating data for the periods indicated.

($ in thousands, except production and per unit data)	THREE MONTHS ENDED SEPTEMBER 30, 2025	THREE MONTHS ENDED SEPTEMBER 30, 2024	INCREASE (DECREASE) AMOUNT	INCREASE (DECREASE) PERCENT
Financial and Operating Results:				
Revenue				
Oil	$ 64,422	$ 56,181	$ 8,241	15%
Natural gas	3,021	2,099	922	44%
Total revenue	$ 67,443	$ 58,280	$ 9,163	16%
Operating Expenses				
Lease operating expense	$ 18,465	$ 11,622	$ 6,843	59%
Production taxes	6,229	5,329	900	17%
General and administrative	5,743	5,231	512	10%
Depletion, depreciation, amortization, and accretion	34,216	24,915	9,301	37%
Equity-based compensation	2,682	2,202	480	22%
Interest Expense	$ 2,381	$ 2,722	$ (341)	(13%)
Commodity Derivative Gain, Net	$ 681	$ 17,368	$ (16,687)	*
Income Tax (Benefit) Expense	$ (254)	$ 6,220	$ (6,474)	(104%)
Production Data:				
Oil (MBbls)	1,079	809	270	33%
Natural gas (MMcf)	3,555	2,326	1,229	53%
Combined volumes (MBoe)	1,671	1,197	474	40%
Daily combined volumes (Boe/d)	18,163	13,009	5,154	40%
Average Realized Prices before Hedging:				
Oil (per Bbl)	$ 59.73	$ 69.43	$ (9.70)	(14%)
Natural gas (per Mcf)	0.85	0.90	(0.05)	(6%)
Combined (per Boe)	40.36	48.69	(8.33)	(17%)
Average Realized Prices with Hedging:				
Oil (per Bbl)	$ 62.71	$ 71.20	$ (8.49)	(12%)
Natural gas (per Mcf)	1.14	0.90	0.24	27%
Combined (per Boe)	42.91	49.89	(6.98)	(14%)
Average Costs (per Boe):				
Lease operating	$ 11.05	$ 9.71	$ 1.34	14%
Production taxes	3.73	4.45	(0.72)	(16%)
General and administrative	3.44	4.37	(0.93)	(21%)
Depletion, depreciation, amortization, and accretion	20.48	20.82	(0.34)	(2%)

*Not meaningful

Oil and Natural Gas Revenue and Volumes. Oil and natural gas revenue increased to $67.4 million for the three months ended September 30, 2025 from $58.3 million for the three months ended September 30, 2024. The increase in oil and natural gas revenue was due to a 40% increase in production volumes, driven by acquisition and development activity (including the Lucero Acquisition), which was partially offset by a 17% decrease in the average realized prices per Boe before hedging for the three months ended September 30, 2025. The increase in production volumes increased oil and natural gas revenue by approximately $19.1 million, while the decrease in average realized prices per Boe before hedging decreased oil and natural gas revenue by approximately $10.0 million.

Our oil price differential to the weighted average benchmark price during the three months ended September 30, 2025 was negative $5.35 per barrel, as compared to a negative $5.80 per barrel during the three months ended September 30, 2024, primarily due to more favorable local market pricing as compared to the benchmark price. Our net realized natural gas price during the three months ended September 30, 2025 was $0.85 per Mcf, representing a 28% realization relative to the weighted average NYMEX natural gas price, compared to a net realized natural gas price of $0.90 per Mcf during the three months ended

September 30, 2024, representing a 43% realization relative to the weighted average NYMEX natural gas price. Fluctuations in our natural gas price differentials and realizations are generally due to several factors such as NGL value net of processing costs, gathering and transportation fees, takeaway capacity relative to production levels, regional storage capacity, and seasonal refinery maintenance temporarily depressing demand. The exact impact of each of these items is difficult to quantify as each of our operators passes through these costs in a different manner.

Lease Operating Expense. Lease operating expense increased to $11.05 per Boe for the three months ended September 30, 2025 from $9.71 per Boe for the three months ended September 30, 2024. The increase per Boe for the three months ended September 30, 2025 compared with the three months ended September 30, 2024 was due in part to a $1.10 per Boe increase in workover costs between periods and a $0.21 per Boe increase in transportation expense included in lease operating expense.

Production Tax Expense. Total production taxes increased to $6.2 million for the three months ended September 30, 2025 from $5.3 million for the three months ended September 30, 2024. Production taxes are primarily based on oil revenue and natural gas production, excluding gains and losses associated with hedging activities. Production taxes as a percentage of oil and natural gas sales before hedging adjustments were 9.2% and 9.1% for the three months ended September 30, 2025 and 2024, respectively.

General and Administrative Expense. General and administrative expense increased to $5.7 million for the three months ended September 30, 2025 from $5.2 million for the three months ended September 30, 2024 primarily due to incremental costs related to becoming an operator. General and administrative expense on a per Boe basis decreased to $3.44 for the three months ended September 30, 2025 from $4.37 for the three months ended September 30, 2024. The decrease in per Boe cost is associated with economies of scale on a 40% increase in production between periods.

DD&A. DD&A increased to $34.2 million for the three months ended September 30, 2025 compared with $24.9 million for the three months ended September 30, 2024. The increase was the result of a 40% increase in production, partially offset by a $0.34 per Boe decrease in the DD&A rate for the three months ended September 30, 2025 compared with the three months ended September 30, 2024. The increase in production accounted for a $9.7 million increase in DD&A expense while the decrease in the DD&A rate accounted for a $0.4 million decrease in DD&A expense.

For the three months ended September 30, 2025, the relationship of capital expenditures, proved reserves and production from certain producing fields yielded a depletion rate (excluding depreciation, amortization and accretion) of $20.32 per Boe compared with $20.67 per Boe for the three months ended September 30, 2024.

Equity-Based Compensation. During the three months ended September 30, 2025, equity-based compensation expense increased to $2.7 million from $2.2 million during the three months ended September 30, 2024. Equity-based compensation expense was higher in 2025 due to additional LTIP RSUs and PSUs awarded to employees and directors at a higher grant date price.

Interest Expense. Interest expense decreased to $2.4 million for the three months ended September 30, 2025 from $2.7 million for the three months ended September 30, 2024. The decrease for the three months ended September 30, 2025 was primarily due to a lower interest rate during the period.

Commodity Derivative Gain, Net. The commodity derivative gain was $0.7 million for the three months ended September 30, 2025 compared with a gain of $17.4 million for the three months ended September 30, 2024. Gain (Loss) on Commodity Derivatives is comprised of (1) cash gains and losses we recognize on settled commodity derivative instruments during the period, and (2) unsettled gains and losses we incur on commodity derivative instruments outstanding at period-end.

The mark-to-market fair value of the unsettled commodity derivative instruments will generally be inversely related to the price movement of the underlying commodity. If commodity price trends reverse from period to period, prior unrealized gains may become unrealized losses and vice versa. These unrealized gains and losses will impact our net income in the period reported. The mark-to-market fair value can create non-cash volatility in our reported earnings during periods of commodity price volatility. We have experienced such volatility in the past and are likely to experience it in the future. Gains on our derivatives generally indicate lower oil revenues in the future while losses indicate higher future oil revenues.

The table below summarizes our commodity derivative gains and losses that were recorded in the periods presented.

	THREE MONTHS ENDED SEPTEMBER 30,	
(in thousands)	**2025**	**2024**
Realized gain on commodity derivatives (1)	$ 4,258	$ 1,430
Unrealized (loss) gain on commodity derivatives (1)	(3,577)	15,938
Total commodity derivative gain	$ 681	$ 17,368

(1) Realized and unrealized gains and losses on commodity derivatives are presented herein as separate line items but are combined for a total commodity derivative gain (loss) in the statements of operations included in this Form 10-Q. Management believes the separate presentation of the realized and unrealized commodity derivative gains and losses is useful because the realized cash settlement portion provides a better understanding of our hedge position.

In the three months ended September 30, 2025, approximately 63% of our oil volumes were covered by financial hedges, which resulted in a realized gain on oil derivatives of $3.2 million. In the three months ended September 30, 2025, a portion of our natural gas volumes was covered by residue gas and NGL financial hedges, which resulted in a realized gain on gas and NGL derivatives of $1.0 million. In the three months ended September 30, 2024, approximately 63% of our oil volumes and none of our natural gas volumes were covered by financial hedges, which resulted in a realized gain on oil derivatives of $1.4 million.

At September 30, 2025, all of our derivative contracts were recorded at their fair value, which was a net asset of $12.3 million, a decrease in value of $3.6 million from the $15.9 million net asset recorded as of June 30, 2025. The decrease was primarily due to the gains realized on commodity derivative contracts in the period.

Income Tax Expense. During the three months ended September 30, 2025, we recorded an income tax benefit of $0.3 million related to federal and state income taxes compared to an income tax expense of $6.2 million for the three months ended September 30, 2024.

The provision for income taxes for the three months ended September 30, 2025 and 2024 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax income primarily due to §162(m) limitations on certain covered employee compensation, other discrete permanent differences related to vesting of RSUs for non-covered employees and state income taxes.

Results of Operations

Nine Months Ended September 30, 2025 Compared with Nine Months Ended September 30, 2024

The following table sets forth selected financial and operating data for the periods indicated.

($ in thousands, except production and per unit data)	NINE MONTHS ENDED SEPTEMBER 30, 2025	NINE MONTHS ENDED SEPTEMBER 30, 2024	INCREASE (DECREASE) AMOUNT	INCREASE (DECREASE) PERCENT
Financial and Operating Results:				
Revenue				
Oil	$ 189,957	$ 177,672	$ 12,285	7%
Natural gas	25,412	8,400	17,012	203%
Total revenue	$ 215,369	$ 186,072	$ 29,297	16%
Operating Expenses				
Lease operating expense	$ 51,949	$ 35,685	$ 16,264	46%
Production taxes	18,181	16,555	1,626	10%
General and administrative	18,185	15,329	2,856	19%
Depletion, depreciation, amortization, and accretion	95,355	73,776	21,579	29%
Equity-based compensation	7,555	5,853	1,702	29%
Interest Expense	$ 7,825	$ 7,510	$ 315	4%
Commodity Derivative Gain, Net	$ 18,960	$ 3,923	$ 15,037	383%
Income Tax (Benefit) Expense	$ 9,416	$ 9,166	$ 250	3%
Production Data:				
Oil (MBbls)	3,116	2,481	635	26%
Natural gas (MMcf)	9,761	6,525	3,236	50%
Combined volumes (MBoe)	4,743	3,568	1,175	33%
Daily combined volumes (Boe/d)	17,373	13,023	4,350	33%
Average Realized Prices before Hedging:				
Oil (per Bbl)	$ 60.96	$ 71.62	$ (10.66)	(15%)
Natural gas (per Mcf)	2.60	1.29	1.31	102%
Combined (per Boe)	45.41	52.15	(6.74)	(13%)
Average Realized Prices with Hedging:				
Oil (per Bbl)	$ 63.90	$ 72.12	$ (8.22)	(11%)
Natural gas (per Mcf)	2.71	1.29	1.42	110%
Combined (per Boe)	47.56	52.49	(4.93)	(9%)
Average Costs (per Boe):				
Lease operating	$ 10.95	$ 10.00	$ 0.95	10%
Production taxes	3.83	4.64	(0.81)	(17%)
General and administrative	3.83	4.30	(0.47)	(11%)
Depletion, depreciation, amortization, and accretion	20.11	20.68	(0.57)	(3%)

Oil and Natural Gas Revenue and Volumes. Oil and natural gas revenue increased to $215.4 million for the nine months ended September 30, 2025 from $186.1 million for the nine months ended September 30, 2024. The increase in oil and natural gas revenue was due to a 33% increase in production volumes, driven by acquisition and development activity (including the Lucero Acquisition), which was partially offset by a 13% decrease in the average realized prices per Boe before hedging for the nine months ended September 30, 2025. The increase in production volumes increased oil and natural gas revenue by approximately $53.4 million, while the decrease in average realized prices per Boe before hedging decreased oil and natural gas revenue by approximately $24.1 million.

During the nine months ended September 30, 2025, $3.3 million and $13.6 million of recoupments of oil and gas revenue, respectively, were recognized as part of the settlement discussed in Note 9 (“Commitments and Contingencies”) to the Condensed Consolidated Financial Statements. Our oil price differential to the weighted average benchmark price during the nine months ended September 30, 2025 was negative $5.33 per barrel, as compared to a negative $6.05 per barrel during the nine months ended September 30, 2024, primarily due to the legal settlement increasing the realized price per Bbl in the period, partially offset by less favorable local market pricing as compared to the benchmark price. Our net realized natural gas price during the nine months ended September 30, 2025 was $2.60 per Mcf, representing a 77% realization relative to the weighted average NYMEX natural gas price, compared to a net realized natural gas price of $1.29 per Mcf during the nine months ended September 30, 2024, representing a 62% realization relative to the weighted average NYMEX natural gas price. The higher realized price was primarily due to the legal settlement increasing the realized price per Mcf in the period. Fluctuations in our natural gas price differentials and realizations are due to several factors such as NGL value net of processing costs, gathering and transportation fees, takeaway capacity relative to production levels, regional storage capacity, and seasonal refinery maintenance temporarily depressing demand. The exact impact of each of these items is difficult to quantify as each of our operators passes through these costs in a different manner.

Lease Operating Expense. Lease operating expense increased to $10.95 per Boe for the nine months ended September 30, 2025 from $10.00 per Boe for the nine months ended September 30, 2024. The increase per Boe for the nine months ended September 30, 2025 compared with the nine months ended September 30, 2024 was due in part to a $1.03 per Boe increase in workover costs between periods.

Production Tax Expense. Total production taxes increased to $18.2 million for the nine months ended September 30, 2025 from $16.6 million for the nine months ended September 30, 2024. Production taxes are primarily based on oil revenue and natural gas production, excluding gains and losses associated with hedging activities. Production taxes as a percentage of oil and natural gas sales before hedging adjustments were 8.4% and 8.9% for the nine months ended September 30, 2025 and 2024, respectively.

General and Administrative Expense. General and administrative expense increased to $18.2 million for the nine months ended September 30, 2025 from $15.3 million for the nine months ended September 30, 2024. During the nine months ended September 30, 2025, $7.1 million of litigation costs were reimbursed as a result of the settlement discussed in Note 9 ("Commitments and Contingencies") to the Condensed Consolidated Financial Statements. Excluding net litigation costs and Lucero Acquisition transaction costs of $5.2 million, general and administrative expense on a per Boe basis decreased to $3.64 for the nine months ended September 30, 2025 from $4.30 for the nine months ended September 30, 2024. The decrease in per Boe cost is associated with economies of scale on a 33% increase in production between periods.

DD&A. DD&A increased to $95.4 million for the nine months ended September 30, 2025 compared with $73.8 million for the nine months ended September 30, 2024. The increase was the result of a 33% increase in production, partially offset by a $0.57 per Boe decrease in the DD&A rate for the nine months ended September 30, 2025 compared with the nine months ended September 30, 2024. The lower DD&A rate was driven by the properties acquired in the Lucero Acquisition in 2025. The increase in production accounted for a $23.6 million increase in DD&A expense while the decrease in the DD&A rate accounted for a $2.0 million decrease in DD&A expense.

For the nine months ended September 30, 2025, the relationship of capital expenditures, proved reserves and production from certain producing fields yielded a depletion rate (excluding depreciation, amortization and accretion) of $19.95 per Boe compared with $20.52 per Boe for the nine months ended September 30, 2024.

Equity-Based Compensation. During the nine months ended September 30, 2025, equity-based compensation expense increased to $7.6 million from $5.9 million during the nine months ended September 30, 2024. Equity-based compensation expense was higher in 2025 due to additional LTIP RSUs and PSUs awarded to employees and directors at a higher grant date price.

Interest Expense. Interest expense increased to $7.8 million for the nine months ended September 30, 2025 from $7.5 million for the nine months ended September 30, 2024. The increase for the nine months ended September 30, 2025 was due to a higher average debt balance during the nine months ended September 30, 2025 compared to the nine months ended September 30, 2024, partially offset by a lower interest rate.

Commodity Derivative Gain, Net. The commodity derivative gain was $19.0 million for the nine months ended September 30, 2025 compared with a gain of $3.9 million for the nine months ended September 30, 2024. Gain (Loss) on Commodity Derivatives is comprised of (1) cash gains and losses we recognize on settled commodity derivative instruments during the period, and (2) unsettled gains and losses we incur on commodity derivative instruments outstanding at period-end.

The mark-to-market fair value of the unsettled commodity derivative instruments will generally be inversely related to the price movement of the underlying commodity. If commodity price trends reverse from period to period, prior unrealized gains may become unrealized losses and vice versa. These unrealized gains and losses will impact our net income in the period reported. The mark-to-market fair value can create non-cash volatility in our reported earnings during periods of commodity price volatility. We have experienced such volatility in the past and are likely to experience it in the future. Gains on our derivatives generally indicate lower oil revenues in the future while losses indicate higher future oil revenues.

The table below summarizes our commodity derivative gains and losses that were recorded in the periods presented.

(in thousands)	NINE MONTHS ENDED SEPTEMBER 30, 2025	2024
Realized gain on commodity derivatives [1]	$ 10,212	$ 1,230
Unrealized gain on commodity derivatives [1]	8,748	2,693
Total commodity derivative gain	$ 18,960	$ 3,923

(1) Realized and unrealized gains and losses on commodity derivatives are presented herein as separate line items but are combined for a total commodity derivative gain (loss) in the statements of operations included in this Form 10-Q. Management believes the separate presentation of the realized and unrealized commodity derivative gains and losses is useful because the realized cash settlement portion provides a better understanding of our hedge position.

In the nine months ended September 30, 2025, approximately 62% of our oil volumes were subject to financial hedges, which resulted in a realized gain on oil derivatives of $9.2 million. In the nine months ended September 30, 2025, a portion of our natural gas volumes was covered by residue gas and NGL financial hedges, which resulted in a realized gain on gas and NGL derivatives of $1.0 million. In the nine months ended September 30, 2024, approximately 58% of our oil volumes and none of our natural gas volumes were covered by financial hedges, which resulted in a realized gain on oil derivatives of $1.2 million.

At September 30, 2025, all of our derivative contracts were recorded at their fair value, which was a net asset of $12.3 million, an increase in value of $8.6 million from the $3.7 million net asset recorded as of December 31, 2024. The increase was primarily due to decreases in forward commodity prices since December 31, 2024 relative to prices on our open commodity derivative contracts.

Income Tax Expense. During the nine months ended September 30, 2025, we recorded an income tax expense of $9.4 million related to federal and state income taxes compared to an income tax expense of $9.2 million for the nine months ended September 30, 2024.

The provision for income taxes for the nine months ended September 30, 2025 and 2024 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax income primarily due to §162(m) limitations on certain covered employee compensation, other discrete permanent differences related to vesting of RSUs for non-covered employees and state income taxes.

Liquidity and Capital Resources

Overview. At September 30, 2025, we had $5.6 million of unrestricted cash on hand and $136.0 million available under the elected commitments in our Revolving Credit Facility. At December 31, 2024, we had $3.0 million of unrestricted cash on hand and $118.0 million available under the elected commitments in our Revolving Credit Facility. We expect that our liquidity going forward will be primarily derived from cash flows from our operations, cash on hand, availability under the Revolving Credit Facility and proceeds from equity or debt offerings and that these sources of liquidity will be sufficient to provide us the ability to fund our material cash requirements for the next twelve months, as described below, including our planned capital expenditures program, as well as dividends and our share repurchase program. We may need to fund acquisitions or other business opportunities that support our strategy through additional borrowings under our Revolving Credit Facility or the issuance of equity or debt. Our primary uses of capital have been for the acquisition and development of our oil and natural gas properties and dividend payments. We continually monitor potential capital sources for opportunities to enhance liquidity or otherwise improve our financial position.

Working Capital. Our working capital balance fluctuates as a result of changes in commodity pricing and production volumes, the collection of revenue receivables, expenditures related to our acquisition and development, and production operations and the impact of our outstanding commodity derivative instruments.

At September 30, 2025, we had a working capital deficit of $9.7 million, compared to a deficit of $49.4 million at December 31, 2024. Current assets increased by $6.1 million while current liabilities decreased by $33.5 million at September 30, 2025, compared to December 31, 2024. The increase in current assets during the nine months ended September 30, 2025 was primarily due to an increase of $7.5 million in our current commodity derivative instruments due to the change in fair value and a $2.6 million increase in cash, partially offset by a $5.0 million decrease in revenue receivable. The decrease in current liabilities during the nine months ended September 30, 2025 was principally due to a decrease of $33.4 million in accounts payable and accrued liabilities as a result of paying accrued oil and gas development costs and accrued employee compensation.

Cash Flows. Our cash flows for the nine months ended September 30, 2025 and 2024 are presented below:

	NINE MONTHS ENDED SEPTEMBER 30,	
(in thousands)	**2025**	**2024**
Net cash from changes in operating activities	$ 132,909	$ 120,309
Net cash from changes in investing activities	(97,904)	(87,098)
Net cash from changes in financing activities	(32,399)	(31,338)
Net change in cash	$ 2,606	$ 1,873

During the nine months ended September 30, 2025, we generated $132.9 million of cash from operations, a $12.6 million increase from the nine months ended September 30, 2024. Cash flows from operating activities are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivative contracts, and by changes in working capital. Any interim cash needs are funded by cash on hand, cash flows from operations or borrowings under our Revolving Credit Facility. We typically enter into commodity derivative transactions covering a substantial, but varying, portion of our anticipated future oil and gas production for the next 12 to 24 months. A minimum level of derivative coverage is required by certain debt covenants. See Part I, Item 3 Quantitative and Qualitative Disclosures about Market Risk.

One of the primary sources of variability in our cash provided by operating activities is commodity price volatility, which we partially mitigate through the use of oil and natural gas commodity derivative contracts. For more information on our outstanding derivatives, see Note 6 (“Derivative Instruments”) to the Condensed Consolidated Financial Statements.

Cash used in investing activities during the nine months ended September 30, 2025 was $97.9 million compared to $87.1 million during the nine months ended September 30, 2024. The $10.8 million increase was primarily related to higher development activity between periods, partially offset by lower acquisition activity. Cash used in investing activities primarily relates to capital expenditures for acquisition and development costs. Our cash used in investing activities reflects actual cash spending, which can lag several months from when the related costs were accrued. As a result, our actual cash spending is not always reflective of current levels of development activity. Acquisition and development activities are discretionary. We monitor our capital expenditures on a regular basis, adjusting the amount up or down, and between projects, depending on projected commodity prices, cash flows and financial returns. We supplement development activity on our asset base with opportunistic acquisitions of near-term drilling opportunities when development activity by our operators on our existing properties does not meet our development objectives. Our cash spending for acquisition activities was $7.4 million and $20.7 million, during the nine months ended September 30, 2025 and 2024, respectively, with the decrease attributed to lower activity levels in the lower commodity price environment.

Cash used in financing activities was $32.4 million and $31.3 million during the nine months ended September 30, 2025 and 2024, respectively. The cash used in financing activities during the nine months ended September 30, 2025 was related to $69.8 million in dividends paid, $3.0 million of net repayments under our Revolving Credit Facility and the $9.2 million value of retained shares paid to fund employee tax withholding in connection with the vesting of restricted stock units, which was partially offset by $49.8 million in cash acquired in the Lucero Acquisition. The cash used in financing activities during the nine months ended September 30, 2024 was related to $47.6 million in dividends paid and the $7.5 million value of retained shares paid to fund employee tax withholding in connection with the vesting of restricted stock units, which was partially offset by $24.0 million of net borrowings under our Revolving Credit Facility.

Revolving Credit Facility. In connection with the Spin-Off, we entered into the secured Revolving Credit Facility with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of banks, as lenders. The Revolving Credit Facility will mature on October 22, 2028.

Under the Revolving Credit Facility, we are permitted to make cash distributions without limit to our equity holders if (i) no event of default or borrowing base deficiency (i.e., outstanding debt (including loans and letters of credit) exceeds the borrowing base) then exists or would result from such distribution and (ii) after giving effect to such distribution, (a) our total outstanding credit usage does not exceed 80% of the least of (the following collectively referred to as “Commitments”): (1) $500 million, (2) our then-effective borrowing base, and (3) the then-effective aggregate amount of the aggregate elected commitments and (b) as of the date of such distribution, the EBITDAX Ratio does not exceed 1.50 to 1.00. If our EBITDAX Ratio does not exceed 2.25 to 1.00, and if our total outstanding credit usage does not exceed 80% of the Commitments, we may also make distributions if our free cash flow (as defined under the Revolving Credit Facility) is greater than $0 and we have delivered a certificate to our lenders attesting to the foregoing.

See Note 5 (“Credit Facility”) to the Condensed Consolidated Financial Statements for further details regarding the Revolving Credit Facility.

Material Cash Requirements. Our material short-term cash requirements include recurring payroll and benefits obligations for our employees, capital and operating expenditures and other working capital needs. If commodity prices improve, our working capital requirements may increase as we spend additional capital, increase production and pay larger settlements on our outstanding commodity derivative contracts. Conversely, working capital requirements would be expected to decrease if commodity prices decline.

Our long-term material cash requirements from currently known obligations include settlements on our outstanding commodity derivative contracts, future obligations to plug, abandon and remediate our oil and gas properties at the end of their productive lives, and operating lease obligations. We cannot provide specific timing for repayments of outstanding borrowings on our Revolving Credit Facility, or the associated interest payments, as the timing and amount of borrowings and repayments cannot be forecasted with certainty and are based on working capital requirements, commodity prices and acquisition and divestiture activity, among other factors. We cannot provide specific timing for other current and long-term liability obligations where we cannot forecast with certainty the amount and timing of such payments, including asset retirement obligations, as the plugging and abandonment of wells is at our discretion and the discretion of the operators and any amounts we may be obligated to pay under our derivative contracts, as such payments are dependent on commodity prices in effect at the time of settlement. See Note 4 (“Fair Value Measurements”) to the Condensed Consolidated Financial Statements for further information on these contracts and their fair values as of September 30, 2025, which fair values represent the estimated cash settlement amount required to terminate such instruments based on forward price curves for commodities as of that date.

Dividends. We paid cash dividends to our equity holders of $69.8 million during the nine months ended September 30, 2025. While we believe that our future cash flows from operations will be able to sustain future dividends, future dividends may change based on a variety of factors, including contractual restrictions, legal limitations (the most common of which are limitations set forth in a company’s organizational documents and insolvency), business developments and the judgment of our Board. Future cash dividends to equity holders are subject to the terms of the Revolving Credit Facility, as previously described. There can be no guarantee that we will be able to pay dividends at current levels or at all or otherwise return capital to our investors in the future.

Capital Expenditures. For the nine months ended September 30, 2025, total capital expenditures was $97.9 million, including development expenditures and our acquisition activity. We expect to fund future capital expenditures with cash generated from operations and, if required, borrowings under our Revolving Credit Facility. The foregoing excludes larger acquisitions, which are typically not included in our annual capital expenditures budget and which may be financed through equity consideration, like the Lucero Acquisition. With our cash on hand, cash flow from operations, and borrowing capacity under our Revolving Credit Facility, we believe that we will have sufficient cash flow and liquidity to fund our budgeted capital expenditures and operating expenses for at least the next twelve months. However, we may seek additional access to capital and liquidity including issuing equity or debt securities and extending maturities. We cannot assure you, however, that any additional capital will be available to us on favorable terms or at all. Our capital expenditures could be curtailed if our cash flows decline or we are otherwise unable to access capital or liquidity. Reductions of capital expenditures used to drill and complete new oil and natural gas wells would likely result in lower levels of oil and natural gas production in the future. Our future success in growing proved reserves and production may be dependent on our ability to access outside sources of capital.

The amount, timing and allocation of capital expenditures are largely discretionary and subject to change based on a variety of factors. If oil and natural gas prices decline below our acceptable levels, or costs increase, we may choose to defer a portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected financial returns and potential to generate near-term cash flow. We may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We will carefully monitor and may adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing and joint venture opportunities, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, change in service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control. For additional information on the impact of changing prices and market conditions on our financial position, see Part I. Item 3 Quantitative and Qualitative Disclosures About Market Risk.

Effects of Inflation and Pricing. The oil and natural gas industry is cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put pressure on the economic stability and pricing structure within the industry. Higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Such changes can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel.

Critical Accounting Policies and Estimates

The critical accounting policies and estimates used in preparing our interim Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2025 are the same as those described in our Annual Report on Form 10-K for the year ended December 31, 2024 except as follows.

Business Combinations

We account for business combinations using the acquisition method of accounting. Under this method, we recognize the identifiable assets acquired and liabilities assumed at their estimated acquisition-date fair values. Transaction and integration costs related to business combinations are expensed as incurred.

In valuing the assets acquired and liabilities assumed, we make various assumptions to estimate fair values. Fair value is a market-based measurement that reflects the assumptions market participants would use in pricing an asset or liability. For the Lucero Acquisition, the most significant assumptions related to the estimated fair value of the proved oil and gas properties. The fair value of these properties was determined using the income approach, which is based on discounted future net cash flows derived from the properties' reserve reports. The valuation relied primarily on unobservable inputs, which are classified as Level 3 within the fair value hierarchy under ASC 820. Key inputs included estimates of future production volumes from the proved reserves, future commodity prices based on forward strip price curves (adjusted for basis differentials), estimates of lease operating, development and abandonment costs, and the application of a discount rate.

Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill and is subject to ongoing impairment evaluation as described. Any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain on bargain purchase. Deferred taxes are recorded for any differences between the assigned values and the tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

A description of our significant accounting policies and fair value measurements is included in Note 2 (“Significant Accounting Policies”) and Note 4 (“Fair Value Measurements”), respectively, to the Condensed Consolidated Financial Statements set forth in Part I, Item 1 Financial Statements.

Recently Issued or Adopted Accounting Pronouncements

For discussion of recently issued or adopted accounting pronouncements, see Note 2 (“Significant Accounting Policies”) to the Condensed Consolidated Financial Statements set forth in Part I, Item 1 Financial Statements.

Off Balance Sheet Arrangements

We currently do not have any off-balance sheet arrangements that have or are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.