Table of Contents

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2026

OR

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

For the transition period from _____ to _____

Commission file number 001-41605

TXO Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**32-0368858**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
400 West 7th Street, Fort Worth, Texas	**76102**
(Address of Principal Executive Offices)	**(Zip Code)**

(817) 334-7800
(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units	**TXO**	**New York Stock Exchange**
Common Units	**TXO**	**NYSE Texas**

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

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

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

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

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

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

The registrant had outstanding 55,446,407 common units as of November 3, 2026.

TABLE OF CONTENTS

	Page
Part I - Financial Information	
Item 1. Financial Statements	1
Consolidated Balance Sheets	1
Consolidated Statements of Operations	2
Consolidated Statements of Cash Flows	3
Consolidated Statements of Partners' Capital	4
Notes to Financial Statements	5
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations	17
Item 3. Quantitative and Qualitative Disclosures About Market Risk	29
Item 4. Controls and Procedures	30
Part II - Other Information	
Item 1. Legal Proceedings	31
Item 1A. Risk Factors	31
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	31
Item 3. Defaults Upon Senior Securities	31
Item 4. Mine Safety Disclosures	31
Item 5. Other Information	31
Item 6. Exhibits	32
Signatures	33

Part I - Financial Information

Item 1. Financial Statements

TXO PARTNERS, L.P.
Consolidated Balance Sheets
(in thousands)

	September 30, 2026 (Unaudited)	December 31, 2025
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 8,633	$ 9,374
Accounts receivable, net	62,925	52,391
Derivative fair value	12,607	18,276
Other	11,306	15,293
Total Current Assets	95,471	95,334
Property and Equipment, at cost – successful efforts method:		
Proved properties	1,251,271	2,336,977
Unproved properties	10,606	18,863
Other	89,578	89,065
Total Property and Equipment	1,351,455	2,444,905
Accumulated depreciation, depletion and amortization	(272,440)	(1,204,261)
Net Property and Equipment	1,079,015	1,240,644
Other Assets:		
Note receivable from related party	7,279	7,131
Derivative fair value	687	5,576
Other	7,935	6,218
Total Other Assets	15,901	18,925
TOTAL ASSETS	$ 1,190,387	$ 1,354,903
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities:		
Accounts payable	$ 41,336	$ 27,979
Deferred payment	-	70,000
Accrued liabilities	51,112	45,776
Derivative fair value	54,471	5,057
Asset retirement obligation, current portion	2,000	3,500
Other current liabilities	2,816	1,605
Total Current Liabilities	151,735	153,917
Long-term Debt	271,100	291,100
Other Liabilities:		
Asset retirement obligation	159,224	217,585
Derivative fair value	11,273	35
Other liabilities	283	534
Total Other Liabilities	170,780	218,154
Commitments and Contingencies		
Partners' Capital:		
Partners' capital	596,772	691,732
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 1,190,387	$ 1,354,903

See accompanying notes to the Consolidated Financial Statements

TXO PARTNERS, L.P.
Consolidated Statements of Operations (Unaudited)
(in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
REVENUES				
Oil and condensate	$ 29,845	$ 66,330	$ 157,857	$ 190,379
Natural gas liquids	10,212	7,504	30,308	23,958
Natural gas	15,036	27,042	46,076	60,743
Total Revenues	55,093	100,876	234,241	275,080
EXPENSES				
Production	43,698	47,864	132,888	133,469
Exploration	170	91	404	224
Taxes, transportation and other	18,437	16,648	57,907	49,763
Depreciation, depletion and amortization	24,226	23,697	77,032	66,810
Accretion of discount in asset retirement obligation	3,219	3,982	10,988	11,623
General and administrative	3,936	4,834	13,501	16,729
Total Expenses	93,686	97,116	292,720	278,618
OPERATING (LOSS) INCOME	(38,593)	3,760	(58,479)	(3,538)
OTHER INCOME (EXPENSE)				
Other income	11,720	4,984	29,064	20,352
Interest income	308	113	604	516
Interest expense	(5,523)	(4,505)	(16,842)	(10,697)
Total Other Income	6,505	592	12,826	10,171
NET (LOSS) INCOME	$ (32,088)	$ 4,352	$ (45,653)	$ 6,633
NET (LOSS) INCOME PER COMMON UNIT				
Basic	$ (0.58)	$ 0.08	$ (0.83)	$ 0.14
Diluted	$ (0.58)	$ 0.08	$ (0.83)	$ 0.14
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING				
Basic	55,446	54,784	55,329	48,079
Diluted	55,446	55,807	55,329	49,006

See accompanying notes to the Consolidated Financial Statements

TXO PARTNERS, L.P.
Consolidated Statements of Cash Flows (Unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2026	**2025**
OPERATING ACTIVITIES		
Net (loss) income	$ (45,653)	$ 6,633
Adjustments to reconcile net (loss) income to net cash provided by operating activities, net of effects of assets acquired and liabilities assumed:		
Depreciation, depletion and amortization	77,032	66,810
Accretion of discount in asset retirement obligation	10,988	11,623
Derivative fair value loss (gain)	132,771	(15,668)
Net cash received from (paid to) derivative counterparties	(59,435)	8,574
Non-cash incentive compensation	9,395	12,835
Gain on sale	(1,403)	-
Other non-cash items	1,110	867
Changes in operating assets and liabilities *(a)*	(8,632)	(5,939)
Cash Provided by Operating Activities	116,173	85,735
INVESTING ACTIVITIES		
Proceeds from sale of property and equipment	101,256	-
Proved property acquisitions	(1,793)	(268,850)
Development costs	(63,657)	(36,018)
Unproved property acquisitions	(706)	(66)
Other property and asset additions	(1,101)	(498)
Cash Provided by (Used by) Investing Activities	33,999	(305,432)
FINANCING ACTIVITIES		
Proceeds from long-term debt	86,000	360,500
Payments on long-term debt	(106,000)	(246,500)
Net proceeds from public offering	-	189,502
Proceeds from sale of units to cover withholding taxes	2,173	1,215
Withholding taxes paid on vesting of restricted units	(2,120)	(2,358)
Debt issuance costs	(85)	(2,429)
Hedge financing cost	(2,126)	-
Payment of deferred acquisition cost	(70,000)	-
Distributions	(58,755)	(82,230)
Cash (Used by) Provided by Financing Activities	(150,913)	217,700
DECREASE IN CASH AND CASH EQUIVALENTS	(741)	(1,997)
Cash and Cash Equivalents, beginning of period	9,374	7,305
Cash and Cash Equivalents, end of period	$ 8,633	$ 5,308

(a) **Changes in Operating Assets and Liabilities**

Accounts receivable	$ (11,591)	$ (4,675)
Other current assets	2,151	(1,726)
Current liabilities	6,293	2,637
Other operating liabilities	(5,485)	(2,175)
	$ (8,632)	$ (5,939)

See accompanying notes to the Consolidated Financial Statements

TXO PARTNERS, L.P.
Consolidated Statements of Partners' Capital (Unaudited)

(in thousands)

	Units	$
Balances, June 30, 2026	55,446	$ 648,053
Net loss	—	(32,088)
Expensing of unit awards	—	3,036
Distributions to unitholders	—	(22,229)
Balances, September 30, 2026	55,446	$ 596,772

	Units	$
Balances, June 30, 2025	54,784	$ 753,024
Net income	—	4,352
Expensing of unit awards	—	3,468
Distributions to unitholders	—	(24,624)
Balances, September 30, 2025	54,784	$ 736,220

	Units	$
Balances, December 31, 2025	54,784	$ 691,732
Net loss	—	(45,653)
Proceeds from sale of units to cover withholding taxes	—	2,173
Withholding taxes paid on vesting of restricted units	—	(2,120)
Expensing of unit awards	662	9,395
Distributions to unitholders	—	(58,755)
Balances, September 30, 2026	55,446	$ 596,772

	Units	$
Balances, December 31, 2024	40,913	$ 609,416
Net income	—	6,633
Net proceeds from sale of units	13,417	189,502
Proceeds from sale of units to cover withholding taxes	—	2,422
Withholding taxes paid on vesting of restricted units	—	(2,358)
Expensing of unit awards	454	12,835
Distributions to unitholders	—	(82,230)
Balances, September 30, 2025	54,784	$ 736,220

See accompanying notes to the Consolidated Financial Statements

TXO PARTNERS, L.P.
Notes to Consolidated Financial Statements (Unaudited)

1. Organization and Summary of Significant Accounting Policies

TXO Partners, L.P. (TXO Partners or the Partnership) is an independent oil and gas company that was formed as a Delaware limited partnership in January 2012 (with an effective inception of operations at January 18, 2012). The operations of TXO Partners are governed by the provisions of the partnership agreement, as amended, executed by the general partner, TXO Partners GP, LLC (the General Partner) and the limited partners. The General Partner is the manager and operator of TXO Partners. The General Partner is managed by the board of directors and executive officers of our General Partner. The members of the board of directors of our General Partner are appointed by MorningStar Oil & Gas, LLC ("MSOG"), as the sole member of our General Partner. TXO Partners will remain in existence unless and until dissolved in accordance with the terms of the partnership agreement.

TXO Partners' assets and liabilities include its investment in an unincorporated joint venture, Cross Timbers Energy, LLC ("Cross Timbers Energy"). TXO Partners owns 50% of Cross Timbers Energy, and TXO Partners is the manager of Cross Timbers Energy. Cross Timbers Energy is governed by a Member Management Committee (MMC) and is comprised of six representatives, three from each group, with each group having one voting member. All matters that come before the MMC require the unanimous consent of the voting members. On the last day of each calendar quarter, Cross Timbers Energy distributes all excess cash to the members based on their ownership percentage of 50% each, except for earnings from the note receivable which is owned 5% by TXO Partners. Cross Timbers Energy's properties are located primarily in the San Juan Basin of New Mexico and Colorado and the Permian Basin of West Texas and New Mexico. Cross Timbers Energy executed purchase and sale agreements with multiple private buyers to sell its oil and gas properties and has begun the process of winding down the joint venture (Note 3).

TXO Partners also has a wholly-owned subsidiary, MorningStar Operating LLC which owns oil and gas assets primarily in the San Juan Basin of New Mexico and Colorado, the Permian Basin of West Texas and New Mexico and the Williston Basin of Montana and North Dakota.

2. Basis of Presentation and Significant Accounting Policies

The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and on the same basis as our audited financial statements as of December 31, 2025 included in our Annual Report on Form 10-K for the year ended December 31, 2025. The consolidated balance sheet as of September 30, 2026 and the consolidated statements of operations and cash flows for the periods presented herein are not audited but reflect all adjustments that are of a normal recurring nature and are necessary for a fair statement of results for the periods shown. Certain information and note disclosures normally included in annual financial statements have been omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). Because the consolidated interim financial statements do not include all of the information and notes required by US GAAP for a complete set of financial statements, they should be read in conjunction with the audited consolidated financial statements referred to above. The results and trends in these interim financial statements may not be indicative of results for the full year.

Significant Accounting Policies

For a complete description of TXO Partners' significant accounting policies, see our annual audited consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2025.

3. Acquisitions and Dispositions

In March 2026, the Partnership announced that Cross Timbers Energy executed three purchase and sale agreements with multiple private buyers to sell oil and gas properties for gross aggregate consideration of approximately $200 million (each a "Cross Timbers Transaction" and collectively, the "Cross Timbers Transactions"), including a purchase and sale agreement with CTOC Energy, LLC ("CTOC") for approximately $123.5 million in aggregate gross consideration.

On April 1, 2026, the first Cross Timbers Transaction closed resulting in net proceeds to TXO Partners of approximately $8.4 million.

On April 30, 2026, the second Cross Timbers Transaction closed resulting in net proceeds to TXO Partners of approximately $30.9 million.

On May 28, 2026, the final Cross Timbers Transaction with CTOC closed resulting in net proceeds to TXO Partners of approximately $60.0 million.

In July 2026, we began the process of winding down Cross Timbers Energy. As part of the initial wind down, we received an initial distribution from Cross Timbers Energy of $95.0 million. We used a portion of the net proceeds to pay the $70.0 million deferred payment for our 2025 purchase of assets from White Rock Energy, LLC, which was due on July 31, 2026. The remainder of the initial distribution was used to pay down debt under our Credit Facility (Note 5).

Due to Cross Timbers Energy selling its oil and gas assets, the carrying value of the joint venture's oil and gas assets and liabilities includes net property and equipment of $0.0 million and asset retirement obligation of $0.0 million, as of September 30, 2026. The net income (loss) related to the joint venture properties, net to TXO Partners, was income of $1.0 million for the three months ended September 30, 2026, a loss of ($2.8) million for the three months ended September 30, 2025, income of $11.4 million for the nine months ended September 30, 2026 and a loss of ($3.1) million for the nine months ended September 30, 2025. We expect to complete the wind down of Cross Timbers Energy by the end of the year.

In July 2025, we completed the acquisition of certain oil and gas assets from White Rock Energy, LLC, which are located in the Elm Coulee field in Montana and North Dakota for cash consideration of $331.6 million (the “WRE Acquisition”), including a deferred payment of $70.0 million which was due on July 31, 2026. Our purchase price allocation included $343.0 million to proved properties, $3.0 million to other properties, $1.7 million to other current assets, $6.9 million to other current liabilities and $9.2 million to asset retirement obligation. The WRE Acquisition was funded by a combination of cash on hand from the Offering (Note 12) and borrowings under our Credit Facility (Note 5).

Pro forma financial information (Unaudited)

The following unaudited pro forma financial information represents a summary of the condensed consolidated results of operations for the three and nine months ended September 30, 2025, assuming the WRE Acquisition and Cross Timbers Transactions had been completed as of January 1, 2025. The pro forma financial information is provided for illustrative purposes only and does not purport to represent what the actual consolidated results of operations would have been. Future results may vary significantly from the results reflected because of various factors.

(in thousands)	Three Months Ended September 30, 2025	Nine Months Ended September 30, 2025
Total revenue	$ 95,097	$ 320,709
Net income	$ 9,975	$ 39,289

4. Related Party Transactions

We earned management fees from Cross Timbers Energy of $0.1 million for the three months ended September 30, 2026 and $1.2 million for the three months ended September 30, 2025. We earned management fees from Cross Timbers Energy of $2.3 million for the nine months ended September 30, 2026 and $3.7 million for the nine months ended September 30, 2025. We do not expect to receive additional management fees as part of the wind down of Cross Timbers Energy.

5. Debt

(in thousands)	September 30, 2026	December 31, 2025
Credit Facility, 7.4% at September 30, 2026 and 7.6% at December 31, 2025	$ 264,000	$ 284,000
September 2016 Loan, 7.0% at September 30, 2026 and 7.4% at December 31, 2025	$ 7,100	$ 7,100
Total Long-term Debt	$ 271,100	$ 291,100

November 2021 Credit Facility

On July 31, 2025, we entered into Amendment No. 5 and Borrowing Base Agreement (“Amendment No. 5”) on our senior secured credit facility (the “Credit Facility”) with certain commercial banks, as the lenders, and JPMorgan Chase Bank, N.A., as the administrative agent. We use the Credit Facility for general corporate purposes. Amendment No. 5 increased the borrowing base from $275 million to $410 million, extended the maturity date to August 30, 2029 and joined certain new Lenders to the Credit Facility. In connection with the Credit Facility, we incurred financing fees and expenses, which are included in other assets on the balance sheets, of approximately $8.7 million as of September 30, 2026 and $8.6 million as of December 31, 2025 before accumulated amortization of $4.7 million as of September 30, 2026 and $3.6 million as of December 31, 2025. We incurred $2.4 million of financing fees and expenses in conjunction with Amendment No. 5. These costs are being amortized over the life of the Credit Facility. Such amortized expenses are recorded as interest expense on the statements of operations.

Redetermination of the borrowing base under the credit facility is based primarily on reserve reports that reflect commodity prices at such time, and occurs semi-annually, in March and September, as well as upon requested interim redeterminations, by the lenders at their sole discretion. We also have the right to request additional borrowing base redeterminations each year at our

discretion. Significant declines in commodity prices may result in a decrease in the borrowing base. These borrowing base declines can be offset by any commodity price hedges we enter. Our obligations under the credit facility are secured by substantially all assets of the Partnership, including, without limitation, (i) our interest in the joint venture, (ii) all our deposit accounts, securities accounts, and commodities accounts, (iii) any receivables owed to us by the joint venture and (iv) any oil and gas properties owned directly by TXO Partners or its wholly-owned subsidiaries. We are required to maintain (i) a current ratio greater than 1.0 to 1.0 and current assets shall include availability under the Credit Facility, but shall exclude the fair value of derivative instruments, and current liabilities shall exclude the fair value of derivative instruments and any advances under the Credit Facility and (ii) a ratio of total net debt to EBITDAX of not greater than 3.0 to 1.0. For purposes of the total net debt-to-EBITDAX ratio ("Leverage Ratio"), total net debt includes total debt for borrowed money (including capital leases and purchase money debt), minus unrestricted cash and cash equivalents on hand at such time (not exceeding $15.0 million in the aggregate), minus the unpaid balance of the FAM Loan. EBITDAX means the sum of (i) net income plus interest expense; income taxes paid; depreciation, depletion and amortization; exploration expenses, including workover expenses; non-cash charges including unrealized losses on derivative instruments; and, any extraordinary or non-recurring charges, minus (ii) any extraordinary or non-recurring income and any non-cash income including unrealized gains on derivative instruments. Our hedge requirements are based on availability under the Credit Facility and the Leverage Ratio. If the Leverage Ratio is greater than 0.75 to 1.00, we are required to hedge at least 50% of reasonably anticipated projected production of proved developed producing reserves for the 24 months following the end of the most recent quarter. If the Leverage Ratio is less than 0.75 to 1.00 and availability under the Credit Facility is greater than 20% of the then current borrowing base, the minimum required hedge volume would be 35% for the 12 months following the end of the most recent quarter. If the Leverage Ratio is less than 0.50 to 1.00 and availability under the Credit Facility is greater than 66.7% of the then current borrowing base, there would be no minimum required hedge volume. Our Credit Facility prohibits us from hedging more than 90% of our reasonably projected production for any fiscal year. Effective with the completion of the spring redetermination in June 2026, we received a waiver of all hedge requirements for months 19 through 24 for the quarters ended June 30, 2026 and September 30, 2026. Under the terms of the Credit Facility, we were in compliance with all of our debt covenants as of September 30, 2026 and December 31, 2025. Additionally, we believe we have adequate liquidity to continue as a going concern for at least the next twelve months from the date of this report.

At our election, interest on borrowings under the Credit Facility is determined by reference to either the secured overnight financing rate ("SOFR") plus an applicable margin between 3.00% and 4.00% per annum (depending on the then-current level of borrowings under the Credit Facility) or the alternate base rate ("ABR") plus an applicable margin between 2.00% and 3.00% per annum (depending on the then-current level of borrowings under the Credit Facility). Interest is generally payable quarterly for loans bearing interest based on the ABR and at the end of the applicable interest period for loans bearing interest at SOFR. We are required to pay a commitment fee to the lenders under the Credit Facility, which accrues at a rate per annum of 0.5% on the average daily unused amount of the lesser of: (i) the maximum commitment amount of the lenders and (ii) the then-effective borrowing base.

September 2016 Loan

On September 30, 2016, TXO Partners entered into an unsecured loan agreement with Cross Timbers Energy (the "FAM Loan"). The proceeds for the loan were taken from the cash held by the offshore subsidiary of Exxon Mobil Corporation and the loan was assigned to the offshore subsidiary (Note 6). The loan matures on November 29, 2029, but is automatically extended should the maturity date of the Credit Facility be extended. In all instances, this loan will mature ninety-one days after the maturity of the Credit Facility. Interest on the loan is the lesser of (a) SOFR plus three and one-quarter of one percent (3.25%) per annum, adjusted monthly or (b) the highest rate permitted by applicable law. Though the note is unsecured, we are required to stay in compliance with the terms of the Credit Facility. As part of the wind down of Cross Timbers Energy, we expect to settle this loan using proceeds from our note receivable from related party (Note 6).

6. Note Receivable from Related Party

We, through our 5% ownership interest in investment assets at Cross Timbers Energy, had a note receivable totaling $7.3 million as of September 30, 2026 and $7.1 million as of December 31, 2025 with a highly-rated, offshore subsidiary of Exxon Mobil Corporation. Under the terms of the agreement, the maturity date is February 10, 2046, but Cross Timbers Energy may demand repayment of all or any portion of the outstanding balance on five business days' notice. Interest is earned based on the quarterly SOFR rate plus 4.3% and is paid quarterly. Interest income totaled $0.3 million in the first nine months of 2026 and $0.2 million in the first nine months of 2025.

The note receivable is treated as a non-current asset, since Cross Timbers Energy does not have any intention of demanding repayment of all or any portion of the outstanding balance at this time. Repayment would require the approval of the Cross Timbers Energy MMC. As part of the wind down of Cross Timbers Energy, we expect the proceeds from this note receivable will be used to pay off our FAM Loan (Note 5) with excess proceeds being paid to TXO Partners.

7. Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state and federal laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The following is a summary of changes in TXO Partners' asset retirement obligation activity for the nine months ended September 30, 2026:

	(in thousands)
Asset retirement obligation, January 1	221,085
Liability divested	(68,418)
Liability settled upon plugging and abandoning wells	(2,431)
Accretion of discount expense	10,988
Asset retirement obligation, September 30	161,224
Less current portion	(2,000)
Asset retirement obligation, long term	$ 159,224

8. Commitments and Contingencies

From time to time, the Partnership is subject to various claims and legal actions arising in the ordinary course of business. In the opinion of management, the ultimate disposition of these matters will not have a material adverse effect on the Partnership.

To date, our expenditures to comply with environmental and occupational health and safety laws and regulations have not been significant and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

9. Fair Value

We periodically use commodity-based and financial derivative contracts to manage exposures to commodity prices. We do not hold or issue derivative financial instruments for speculative or trading purposes. We periodically enter into futures contracts, collars, energy swaps, swaptions and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales (Note 10).

Fair Value of Financial Instruments

Because of their short-term maturity, the fair value of cash and cash equivalents, accounts receivable and accounts payable approximates their carrying values at September 30, 2026 and December 31, 2025. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	September 30, 2026		December 31, 2025	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Note receivable from related party	$ 7,279	$ 7,279	$ 7,131	$ 7,131
Long-term debt	$ (271,100)	$ (271,100)	$ (291,100)	$ (291,100)
Derivative asset	$ 13,294	$ 13,294	$ 23,852	$ 23,852
Derivative liability	$ (65,744)	$ (65,744)	$ (5,092)	$ (5,092)

The fair value of our note receivable from related party approximates the carrying amount because the interest rate is based on current market interest rates and can be called upon five business days' notice (Note 6). The fair value of our long-term debt approximates the carrying amount because the interest rate is reset periodically at then current market rates (Note 5).

The fair value of our note receivable from related party (Note 6), derivative asset/(liability) (Note 10) and our long-term debt (Note 5) is measured using Level II inputs, and are determined by either market prices on an active market for similar assets or other market-corroborated prices. Counterparty credit risk is considered when determining the fair value of our note receivable and derivative asset (liability). Since our counterparty is highly rated, the fair value of our note receivable from related party does not require an adjustment to account for the risk of nonperformance by the counterparty, however, an adjustment for counterparty credit risk has been applied to the derivative asset (liability).

The following table summarizes our fair value measurements and the level within the fair value hierarchy in which the fair value measurements fall.

	Fair Value Measurements	
	September 30, 2026	December 31, 2025
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Other Observable Inputs (Level 2)
Note receivable from related party	$ 7,279	$ 7,131
Long-term debt	$ (271,100)	$ (291,100)
Derivative asset	$ 13,294	$ 23,852
Derivative liability	$ (65,744)	$ (5,092)

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments whenever events or circumstances indicate that the carrying value of those assets may not be recoverable and are based upon Level 3 inputs. These assets and liabilities can include assets and liabilities acquired in a business combination, proved and unproved oil and natural gas properties, asset retirement obligations and other long-lived assets that are written down to fair value when they are impaired. Such fair value estimates require assumptions and judgments regarding the existence of liabilities, the amount and timing of cash outflows required to settle the liability, what constitutes adequate restoration, inflation factors, credit adjusted discount rates, and consideration of changes in legal, regulatory, environmental and political environments.

We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. We review our oil and natural gas properties by asset group. The estimated future net cash flows are based upon the underlying reserves and anticipated future pricing. An impairment loss is recognized if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of a particular asset, the Partnership recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of such assets. The fair value of the proved properties is measured based on the income approach, which incorporates a number of assumptions involving expectations of future product prices, which the Partnership bases on the forward-price curves, estimates of oil and gas reserves, estimates of future expected operating and capital costs and a risk adjusted discount rate of 10%. These inputs are categorized as Level 3 in the fair value hierarchy.

Commodity Price Hedging Instruments

We periodically enter into futures contracts, energy swaps, swaptions, collars and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas and natural gas liquids sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. See Note 10.

The fair value of our derivatives contracts consists of the following:

	Asset Derivatives		Liability Derivatives	
(in thousands)	September 30, 2026	December 31, 2025	September 30, 2026	December 31, 2025
Derivatives not designated as hedging instruments:				
Crude oil futures and differential swaps	$ -	$ 21,771	$ (57,715)	$ —
Natural gas liquids futures	$ 44	$ 19	$ —	$ —
Natural gas futures, collars and basis swaps	$ 13,250	$ 2,062	$ (8,029)	$ (5,092)
Total	$ 13,294	$ 23,852	$ (65,744)	$ (5,092)

Derivative fair value (gain) loss, included as part of the related revenue line on the consolidated income statements, comprises the following components:

	Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	2026	2025	2026	2025
Net cash paid to (received from) counterparties	$ 20,607	$ (3,070)	$ 59,435	$ (8,574)
Non-cash change in derivative fair value	$ 37,328	$ (7,250)	$ 73,336	$ (7,094)
Derivative fair value (gain) loss	$ 57,935	$ (10,320)	$ 132,771	$ (15,668)

Concentrations of Credit Risk

Our receivables are from a diverse group of companies including major energy companies, pipeline companies, marketing companies, local distribution companies and end-users in various industries. Letters of credit or other appropriate security are obtained as considered necessary to limit risk of loss from the other companies. We currently have greater concentrations of credit with several investment-grade (BBB- or better) rated companies.

10. Commodity Sales Commitments

Our policy is to consider hedging a portion of our production at commodity prices the general partner deems attractive. While there is a risk we may not be able to realize the benefit of rising prices, the general partner may enter into hedging agreements because of the benefits of predictable, stable cash flows.

We periodically enter futures contracts, energy swaps, swaptions and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We also enter into price collars, which set a ceiling and floor price to hedge our exposure to price fluctuations on commodity prices. When actual commodity prices exceed the ceiling price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the floor price, we receive this difference from the counterparty. If the actual commodity price falls in between the ceiling and floor price, there is no cash settlement.

Crude Oil

We have entered into crude oil futures contracts and swap agreements that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments.

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl
October 2026—December 2026	10,000	$ 59.29
January 2027—June 2027	4,500	$ 63.41
July 2027—December 2027	4,500	$ 65.32
January 2028—March 2028	3,000	$ 63.07

The price we receive for our oil production is generally different than the NYMEX price because of changes in the roll component of the NYMEX price due to the timing of when the monthly NYMEX price is set. We have entered sell basis swap agreements that effectively fix the roll component of the NYMEX price for the production and periods shown below.

Production Period	Bbls per Day	Weighted Average Roll Price per Bbl (a)
October 2026-December 2026	4,000	$ 1.80

a) Increases to NYMEX oil price for roll component.

We have also entered into oil collars, for which we paid a premium of $2.1 million that set a ceiling and floor price for the production and periods shown below.

Production Period	Bbl per Day	Weighted Average NYMEX Price per Bbl Floor	Ceiling
January 2027—December 2027	2,500	$ 70.00	$ 85.00

In October 2026, we entered into a calendar year 2028 oil swaption contract for 3,880 barrels per day at a strike price of $80.00 per barrel. Swaptions are derivative contracts that give counterparties the option to exercise certain derivative contracts. The volumes and prices (i) will only be effective if the option is exercised by the applicable counterparties and (ii) in the periods in which such volumes would be settled, in the event that the applicable counterparties exercise their option.

Net settlements on oil futures and sell basis swap contracts decreased oil revenues by $22.4 million in the three months ended September 30, 2026 and $0.1 million in the three months ended September 30, 2025. Net settlements on oil futures and sell basis swap contracts decreased oil revenues by $59.2 million in the nine months ended September 30, 2026 and increased oil revenues by $2.0 million in the nine months ended September 30, 2025. An unrealized loss decreased oil revenues by $39.4 million in the three months ended September 30, 2026 and an unrealized gain increased oil revenues by $0.3 million in the three months ended September 30, 2025. An unrealized loss decreased oil revenues by $81.6 million in the nine months ended September 30, 2026 and an unrealized gain increased oil revenues by $6.7 million in the nine months ended September 30, 2025.

Natural Gas Liquids

We have entered into natural gas liquids futures contracts and swap agreements for ethane that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 9.

Production Period	Gallons per Day	Weighted Average NGL OPIS Price per Gallon
Ethane		
January 2027—March 2027	14,700	$ 0.29

Net settlements on NGL futures contracts had no impact on NGL revenues in the three months ended September 30, 2026 and no impact on NGL revenues in the three months ended September 30, 2025. Net settlements on NGL futures contracts had no impact on NGL revenues in the nine months ended September 30, 2026 and had no impact on NGL revenues in the nine months ended September 30, 2025. An unrealized loss decreased NGL revenues by $14.0 thousand in the three months ended September 30, 2026 and an unrealized gain increased NGL revenues by $15.0 thousand in the three months ended September 30, 2025. An unrealized gain increased NGL revenues by $25.0 thousand in the nine months ended September 30, 2026 and $14.0 thousand in the nine months ended September 30, 2025.

Natural Gas

We have entered into natural gas futures contracts and swap agreements that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 9.

Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu
October 2026—December 2026	50,000	$ 3.93
January 2027—March 2027	42,500	$ 4.36
April 2027—December 2027	32,500	$ 3.76
January 2028—March 2028	20,000	$ 4.18

We have also entered into gas collars that set a ceiling and floor price for the production and periods shown below.

Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu Floor	Ceiling
January 2028—March 2028	10,000	$ 3.50	$ 5.40

The price we receive for our gas production is generally less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors. We have entered into sell basis swap agreements that effectively fix the basis adjustment for the San Juan Basin delivery location for the production and periods shown below.

Production Period	MMBtu per Day	Weighted Average Sell Basis Price per MMBtu(a)
October 2026—March 2028	30,000	$ (0.89)

(a) Reductions to NYMEX gas price for delivery location

Net settlements on gas futures and sell basis swap contracts increased gas revenues by $1.8 million in the three months ended September 30, 2026 and $3.1 million in the three months ended September 30, 2025. Net settlements on gas futures and sell basis swap contracts decreased gas revenues by $0.2 million in the nine months ended September 30, 2026 and increased gas revenues by $6.6 million in the nine months ended September 30, 2025. An unrealized gain to record the fair value of derivative contracts increased gas revenues by $2.1 million in the three months ended September 30, 2026 and $6.9 million in the three months ended September 30, 2025. An unrealized gain to record the fair value of derivative contracts increased gas revenues by $8.3 million in the nine months ended September 30, 2026 and $0.4 million in the nine months ended September 30, 2025.

11. Earnings per Unit

The following represents basic and diluted earnings per common unit for the three and nine months ended September 30, 2026 and 2025:

(in thousands, except per unit data)	Net Income (Loss)	Units	Income (Loss) per Unit
Three Months Ended September 30, 2026			
Basic	$ (32,088)	55,446	$ (0.58)
Dilutive effect of phantom units	—	—	
Diluted	$ (32,088)	55,446	$ (0.58)
Three Months Ended September 30, 2025			
Basic	$ 4,352	54,784	$ 0.08
Dilutive effect of phantom units	—	1,023	
Diluted	$ 4,352	55,807	$ 0.08
Nine Months Ended September 30, 2026			
Basic	$ (45,653)	55,329	$ (0.83)
Dilutive effect of phantom units	—	—	
Diluted	$ (45,653)	55,329	$ (0.83)
Nine Months Ended September 30, 2025			
Basic	$ 6,633	48,079	$ 0.14
Dilutive effect of phantom units	—	927	
Diluted	$ 6,633	49,006	$ 0.14

All restricted units, totaling 1.2 million, were excluded from the calculation of earnings per common unit for the three months ended September 30, 2026, and all restricted units, totaling 1.3 million, were excluded from the calculation of earnings per common unit for the nine months ended September 30, 2026 because the units are anti-dilutive. No units were excluded for the three months ended September 30, 2025 or the nine months ended September 30, 2025.

12. Partners' Capital

During 2026, we have paid $58.8 million of distributions to our Common unitholders. The following is a summary of distributions paid in 2026.

Period	Distribution per Unit	Payment Date
Fourth Quarter, 2025	$ 0.30	3/17/2026
First Quarter, 2026	$ 0.36	5/22/2026
Second Quarter, 2026	$ 0.40	8/21/2026

On November 3, 2026, the board of directors of our general partner declared a cash distribution of $0.44 per common unit for the quarter ended September 30, 2026. The distribution will be paid on November 20, 2026, to unitholders of record on November 13, 2026.

On May 15, 2025, we completed an underwritten public offering for the sale of 11,666,667 common units at a price of $15.00 per common unit resulting in proceeds of approximately $165.6 million net of underwriting discounts, commissions and other costs. On May 19, 2025, we completed the sale of an additional 1,750,000 common units at a price of $15.00 per common unit pursuant to the underwriter's exercise in full of its option to purchase additional common units in the Offering, resulting in additional net proceeds of approximately $23.9 million, after deducting underwriting discounts, commissions and other costs. We used the net proceeds from the Offering to fund a portion of the cash consideration for the WRE Acquisition (Note 3).

13. Revenue from Contracts with Customers

The Partnership recognizes sales of oil, natural gas, and NGLs when it satisfies a performance obligation by transferring control of the product to a customer, in an amount that reflects the consideration to which the Partnership expects to be entitled in exchange for the product.

As discussed in Note 10, the Partnership recognizes the impact of derivative gains and losses as a component of revenue. See table below for the reconciliation of revenue from contracts with customers and derivative gains and losses.

	Three Months Ended September 30, 2026			
	Oil and condensate	Natural gas liquids	Natural gas	Total Revenues
	(in thousands)			
Revenue from customers	$ 91,610	$ 10,226	$ 11,192	$ 113,028
Unrealized gain (loss) on derivatives	(39,376)	(14)	2,062	(37,328)
Realized gain (loss) on derivatives	(22,389)	—	1,782	(20,607)
Total revenues	$ 29,845	$ 10,212	$ 15,036	$ 55,093

	Three Months Ended September 30, 2025			
	Oil and condensate	Natural gas liquids	Natural gas	Total Revenues
	(in thousands)			
Revenue from customers	$ 66,115	$ 7,489	$ 16,952	$ 90,556
Unrealized gain (loss) on derivatives	291	15	6,944	7,250
Realized gain (loss) on derivatives	(76)	—	3,146	3,070
Total Revenues	$ 66,330	$ 7,504	$ 27,042	$ 100,876

	Nine Months Ended September 30, 2026			
	Oil and condensate	Natural gas liquids	Natural gas	Total Revenues
	(in thousands)			
Revenue from customers	$ 298,707	$ 30,283	$ 38,022	$ 367,012
Unrealized gain (loss) on derivatives	(81,612)	25	8,251	(73,336)
Realized gain (loss) on derivatives	(59,238)	—	(197)	(59,435)
Total revenues	$ 157,857	$ 30,308	$ 46,076	$ 234,241

	Nine Months Ended September 30, 2025			
	Oil and condensate	Natural gas liquids	Natural gas	Total Revenues
	(in thousands)			
Revenue from customers	$ 181,676	$ 23,944	$ 53,792	$ 259,412
Unrealized gain (loss) on derivatives	6,683	14	397	7,094
Realized gain (loss) on derivatives	2,020	—	6,554	8,574
Total Revenues	$ 190,379	$ 23,958	$ 60,743	$ 275,080

Natural Gas and NGL Sales

Under our natural gas processing contracts, we deliver natural gas to a midstream processing entity at the wellhead or at the inlet of a facility. The midstream provider gathers and processes the product, and both the residue gas and the resulting natural gas liquids are sold at the tailgate of the plant. The Partnership's natural gas production is primarily sold under market-sensitive contracts that are typically priced at a differential to the published natural gas index price for the producing area due to the natural gas quality and the proximity to the market. We evaluated these arrangements and determined that control of the products transfers at the tailgate of the plant, meaning that the Partnership is the principal, and the third-party purchaser is its customer. As such, we present the gas and NGL sales on a gross basis and the related gathering and processing costs as a component of taxes, transportation, and other expenses on the statement of operations.

Oil and Condensate Sales

Oil production is typically sold at the wellhead or at the outlet of a gathering system under market-sensitive contracts at an index price, net of pricing differentials. The Partnership recognizes revenue when control transfers to the purchaser at the wellhead at the net price received from the customer.

Production imbalances

The Partnership uses the sales method to account for production imbalances. If the Partnership's sales volumes for a well exceed the Partnership's proportionate share of production from the well, a liability is recognized to the extent that the Partnership's share of estimated remaining recoverable reserves from the well is insufficient to satisfy the imbalance. No receivables are recorded for those wells on which the Partnership has taken less than its proportionate share of production.

Contract Balances

Under the Partnership's product sales contracts, its customers are invoiced once the Partnership's performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Partnership's product sales contracts do not give rise to contract assets or contract liabilities.

Performance Obligations

The majority of the Partnership's sales are short-term in nature with a contract term of one year or less. For those contracts, the Partnership has utilized the practical expedient in ASC 606-10-50-14 exempting the Partnership from disclosures of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original duration of one year or less.

For the Partnership's product sales that have a contract term greater than one year, the Partnership has utilized the practical expedient in ASC 606-10-50-14(a), which states the Partnership is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligation is not required.

14. Employee Benefit Plans

In January 2026, the Compensation Committee of the Board (the "Compensation Committee") approved grants of 632,353 time-vesting phantom units with distribution equivalent rights to the non-employee directors, officers and certain key employees. These phantom units will vest ratably over a three-year period for the officers and key employees and will fully vest on the one-year

anniversary of the grant for the non-employee directors. The phantom units will be settled in common units and distribution equivalents will be paid to holders of outstanding phantom units, including unvested phantom units.

Additionally, in January 2026, the Compensation Committee approved grants of 510,552 performance-vesting phantom units to the officers and certain key employees. These performance-based phantom units will be earned based on the Company's performance during the 2026 calendar year according to certain performance objectives and will vest in one-half increments on January 31, 2028 and January 31, 2029. Prior to determination of the achievement of the performance objectives, distribution equivalent rights will be paid according to the target number of phantom unit grants; following determination of the number of earned phantom units based on achievement of the performance objectives, distribution equivalent rights will be paid according to the number of earned phantom units. The phantom units will be settled in common units and distribution equivalents will be paid to holders of outstanding phantom units, including unvested phantom units.

Additionally, in January 2025, the Compensation Committee approved grants of 249,380 performance-vesting phantom units to the officers and certain key employees. Based on the results of the Company's performance during 2025 according to certain performance objectives, 243,142 performance-vesting phantom units were earned and will vest in one-half increments on January 31, 2027 and January 31, 2028. The phantom units will be settled in common units and distribution equivalents will be paid to holders of outstanding phantom units, including unvested phantom units.

We recognized compensation expense related to these and prior grants of $9.4 million for the nine months ended September 30, 2026 and $12.8 million for the nine months ended September 30, 2025. As of September 30, 2026, we had total deferred compensation expense of $18.9 million. For these non-vested unit awards, we estimate that compensation expense for service periods after September 30, 2026 will be $3.0 million in 2026, $9.3 million in 2027, $6.1 million in 2028 and $0.5 million in 2029. The weighted average remaining vesting period is 1.6 years.

15. Accrued Liabilities

Accrued liabilities consist of the following at September 30, 2026 and December 31, 2025:

	September 30, 2026	December 31, 2025
Accrued production expenses	$ 20,066	$ 27,409
Accrued capital expenditures	$ 20,357	$ 4,826
Accrued bonuses	$ 4,557	$ 6,100
Accrued ad valorem taxes	$ 2,264	$ 3,978
Accrued severance taxes	$ 3,512	$ 2,944
Other accrued liabilities	$ 356	$ 519
Total accrued liabilities	$ 51,112	$ 45,776

16. Segment Reporting

We have one reportable segment, our exploration and production of oil, natural gas and natural gas liquids segment ("E&P segment"). Our E&P segment derives revenues from customers by selling oil, natural gas and natural gas liquids under contracts of various terms and durations (See Note 13). The operating segments within the reportable segment have been aggregated based on the similarity of their economic and other characteristics, including product type and services. All of our assets are located in the United States, and all revenues are attributable to United States customers.

The Partnership's Chief Operating Decision Maker ("CODM") is a group of executives, including the Co-Chief Executive Officers. The CODM assesses performance for the E&P segment and decides how to allocate resources based on cash provided by operations which is also reported on the statement of cash flows as consolidated cash provided by operations. The measure of segment assets is reported on the balance sheet as total consolidated assets.

The CODM uses net income to evaluate income generated from segment assets in deciding whether to reinvest profits into the E&P segment or to pay distributions. Additionally, our CODM is provided information on segment income from operations and cash provided by operating activities to evaluate segment performance.

Selected financial information related to our one reportable segment is included below:

(in thousands)	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	2026	2025
REVENUES				
Oil and condensate	$ 29,845	$ 66,330	$ 157,857	$ 190,379
Natural gas liquids	10,212	7,504	30,308	23,958
Gas	15,036	27,042	46,076	60,743
Total Revenues	55,093	100,876	234,241	275,080
EXPENSES				
Production	43,698	47,864	132,888	133,469
Exploration	170	91	404	224
Taxes, transportation and other	18,437	16,648	57,907	49,763
Depreciation, depletion, and amortization	24,226	23,697	77,032	66,810
Accretion of discount in asset retirement obligation	3,219	3,982	10,988	11,623
General and administrative	3,936	4,834	13,501	16,729
Total Expenses	93,686	97,116	292,720	278,618
OPERATING (LOSS) INCOME	(38,593)	3,760	(58,479)	(3,538)
OTHER INCOME				
Other income	11,720	4,984	29,064	20,352
SEGMENT (LOSS) INCOME FROM OPERATIONS	$ (26,873)	$ 8,744	$ (29,415)	$ 16,814
Reconciliation:				
Interest income	308	113	604	516
Interest expense	(5,523)	(4,505)	(16,842)	(10,697)
Other Expense	(5,215)	(4,392)	(16,238)	(10,181)
NET (LOSS) INCOME	$ (32,088)	$ 4,352	$ (45,653)	$ 6,633
CASH (USED BY) PROVIDED BY OPERATING ACTIVITIES	$ 33,665	$ 28,271	$ 116,173	$ 85,735

17. Supplemental Cash Flow Information

Interest payments totaled $15.7 million for the nine months ended September 30, 2026 and $9.7 million for the nine months ended September 30, 2025. State income tax payments were $0.1 million during the nine months ended September 30, 2026 and $0.3 million during the nine months ended September 30, 2025.

18. Subsequent Events

We have evaluated subsequent events through the date the financial statements were available to be issued. See Note 10.

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

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in Item 1 of this Quarterly Report on Form 10-Q (this "Quarterly Report"). Additionally, the following discussion and analysis should be read in conjunction with our audited consolidated financial statements and notes thereto and the related "Management's Discussion and Analysis of Financial Condition and Results of Operations," included in our Annual Report on Form 10-K for the year ended December 31, 2025.

Unless otherwise stated or the context indicates otherwise, references in this Quarterly Report to "our general partner" refer to TXO Partners GP, LLC, a Delaware limited liability company, and the terms "partnership," the "Company," "we," "our," "us" or similar terms refer to TXO Partners, L.P., a Delaware limited partnership (the "Partnership" or "TXO Partners") and its subsidiaries. Unless otherwise indicated, throughout this discussion the term "MBoe" refers to thousands of barrels of oil equivalent quantities produced for the indicated period, with natural gas and NGL quantities converted to Bbl on an energy equivalent ratio of six Mcf to one barrel of oil.

Cautionary Statement Regarding Forward-Looking Statements

Some of the information in this Quarterly Report on Form 10-Q may contain "forward-looking statements." All statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Quarterly Report on Form 10-Q, words such as "may," "assume," "forecast," "could," "should," "will," "plan," "believe," "anticipate," "intend," "estimate," "expect," "project," "budget" and similar expressions are used to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events at the time such statement was made. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading "Risk Factors" included in our Annual Report on Form 10-K for the year ended December 31, 2025, filed with the SEC on February 26, 2026, as amended.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development and production of oil, natural gas and natural gas liquids ("NGL"). We disclose important factors that could cause our actual results to differ materially from our expectations as discussed under "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Quarterly Report on Form 10-Q. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statement include:

- commodity price volatility;
- the impact of epidemics, outbreaks or other public health events, and the related effects on financial markets, worldwide economic activity and our operations;
- uncertainties about our estimated oil, natural gas and NGL reserves, including the impact of commodity price declines on the economic producibility of such reserves, and in projecting future rates of production;
- the concentration of our operations in the Permian Basin, the San Juan Basin and the Williston Basin;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- lack of transportation and storage capacity as a result of oversupply, government regulations or other factors;
- lack of availability of drilling and production equipment and services;
- potential financial losses or earnings reductions resulting from our commodity price risk management program or any inability to manage our commodity risks;
- failure to realize expected value creation from property acquisitions and trades;
- access to capital and the timing of development expenditures;
- environmental, weather, drilling and other operating risks;
- regulatory changes, including potential shut-ins or production curtailments mandated by the Railroad Commission of Texas;

- competition in the oil and natural gas industry;
- loss of production and leasehold rights due to mechanical failure or depletion of wells and our inability to re-establish their production;
- our ability to service our indebtedness;
- cost inflation;
- changes to U.S. and foreign governmental regulation, taxation and tariffs;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, the recent military conflict involving Iran, attacks in the Red Sea and other continued hostilities in the Middle East and other sustained military campaigns, the armed conflict in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;
- evolving cybersecurity risks such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insider or other with authorized access, cyber or phishing-attacks, ransomware, social engineering, physical breaches or other actions; and
- risks related to our ability to expand our business, including through the recruitment and retention of qualified personnel.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, our reserve and PV-10 estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Quarterly Report on Form 10-Q occur, or should underlying assumptions prove to be incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Quarterly Report on 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.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Quarterly Report on Form 10-Q.

Overview

We are an independent oil and natural gas company focused on the acquisition, development, optimization and exploitation of oil, natural gas and natural gas liquid reserves in North America. Our properties are predominately located in the Permian Basin of New Mexico and Texas, the San Juan Basin of New Mexico and Colorado and the Williston Basin of Montana and North Dakota.

Recent Developments

Cross Timbers Energy, LLC Disposition

In March 2026, we announced that Cross Timbers Energy executed three purchase and sale agreements with multiple private buyers to sell oil and gas properties for gross aggregate consideration of approximately $200.0 million, including a purchase and sale agreement with CTOC for approximately $123.5 million in gross aggregate consideration.

On April 1, 2026, the first Cross Timbers Transaction closed resulting in net proceeds of approximately $8.4 million.

On April 30, 2026, the second Cross Timbers Transaction closed resulting in net proceeds of approximately $30.9 million.

On May 28, 2026, the final Cross Timbers Transaction with CTOC closed resulting in net proceeds to TXO Partners of approximately $60.0 million.

In July 2026, we began the process of winding down Cross Timbers Energy. As part of the initial wind down, we received an initial distribution from Cross Timbers Energy of $95.0 million. We used a portion of the net proceeds to pay the $70.0 million deferred payment for our 2025 purchase of assets from White Rock Energy, LLC, which was due on July 31, 2026. The remainder of the initial distribution was used to pay down debt under our Credit Facility.

Market Outlook

The oil and natural gas industry is cyclical and commodity prices are highly volatile. For example, during the period from January 1, 2025 through September 30, 2026, NYMEX prices for crude oil and natural gas reached a high of $112.95 per Bbl and $7.46 per MMBtu, respectively, and a low of $55.27 per Bbl and $2.52 per MMBtu, respectively. Oil prices increased in the first half of 2026 due to hostilities in the Middle East which led to unexpected production cuts and supply constraints. While direct hostilities have dissipated, the continuing supply constraints due to difficulties transiting the Strait of Hormuz have continued to keep oil prices elevated.

We expect the crude oil and natural gas markets will continue to be volatile in the future. Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production. Please see “Risk Factors--Risks Related to the Natural Gas, NGL and Oil Industry and Our Business--Commodity prices are volatile--A sustained decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments” in our Annual Report on Form 10-K for the year ended December 31, 2025.

With our anticipated cash flows from our long-lived property base, we intend to allocate funds to prudently meet our goals. These goals include the highest projected economic returns on our capital budget, acquisition opportunities that fulfill our strategy, and cash distributions. From time to time, we may choose to prioritize the repayment of debt to support the longer-term financial stewardship of our business. At other times, we may modify our capital budget or cash distribution policy. We will use all of these tools to support our underlying strategy as a “production and distribution” enterprise.

Concerns over global economic conditions, energy costs, supply chain disruptions, increased demand, labor shortages associated with a fully employed U.S. labor force, war, geopolitical issues, inflation, tariffs, the availability and cost of credit and the United States financial markets and other factors have contributed to increased economic uncertainty and diminished expectations for the global economy. Rising inflation has been pervasive for the last several years, increasing the cost of salaries, wages, supplies, material, freight, and energy. While we have seen inflation moderate, inflation continues to run higher than the Federal Reserve target, resulting in higher costs. We continue to undertake actions and implement plans to address these pressures and protect the requisite access to commodities and services, however, these mitigation efforts may not succeed or may be insufficient. Nevertheless, we expect for the foreseeable future to experience inflationary pressure on our cost structure. Principally, commodity costs for steel, diesel and chemicals required for drilling, higher transportation and fuel costs and wage increases have increased our operating costs. We do not expect these cost increases to reverse in the short term. Typically, as prices for oil and natural gas increase, so do associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion to prices. We cannot predict the future inflation rate but to the extent these higher costs do not begin to reverse or start to increase again, we may experience a higher cost environment going forward. If we are unable to recover higher costs through higher commodity prices, our current revenue stream, estimates of future reserves, borrowing base calculations, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions would all be significantly impacted.

We are taking actions to mitigate inflationary pressures. We are working closely with our suppliers and contractors to ensure availability of supplies on site, especially fuel, steel and chemical supplies, which are critical to many of our operations. However, these mitigation efforts may not succeed or may be insufficient.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our operations, including:

- production volumes;
- realized prices on the sale of oil, NGLs and natural gas;
- production expenses;
- acquisition and development expenditures;
- Adjusted EBITDAX; and
- Cash Available for Distribution.

Non-GAAP Financial Measures

Adjusted EBITDAX

We include in this Quarterly Report the non-GAAP financial measure Adjusted EBITDAX and provide our calculation of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to net income (loss), our most directly comparable financial measures calculated and presented in accordance with GAAP. We define Adjusted EBITDAX as net income (loss) before (1) interest income, (2) interest expense, (3) depreciation, depletion and amortization, (4) impairment expenses, (5) accretion of discount on asset retirement obligations, (6) exploration expenses, (7) unrealized (gains) losses on commodity derivative contracts, (8) non-cash incentive compensation, (9) non-cash (gain) loss on forgiveness of debt and (10) certain other non-cash expenses.

Adjusted EBITDAX is used as a supplemental financial measure by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to more effectively evaluate our operating performance and our results of operation from period to period and against our peers without regard to financing methods, capital structure or historical cost basis. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX is not a measurement of our financial performance under GAAP and should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as indicators of our operating performance. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax burden, as well as the historic costs of depreciable assets, none of which are reflected in Adjusted EBITDAX. Our presentation of Adjusted EBITDAX should not be construed as an inference that our results will be unaffected by unusual or non-recurring items. Our computations of Adjusted EBITDAX may not be identical to other similarly titled measures of other companies.

Cash Available for Distribution

Cash available for distribution is not a measure of net income or net cash flow provided by or used in operating activities as determined by GAAP. Cash available for distribution is a supplemental non-GAAP financial measure used by our management and by external users of our financial statements, such as investors, lenders and others (including industry analysts and rating agencies who will be using such measure), to assess our ability to internally fund our exploration and development activities, pay distributions, and to service or incur additional debt. We define cash available for distribution as Adjusted EBITDAX less net cash interest expense, exploration expense, non-recurring (gain) / loss and development costs. Development costs include all of our capital expenditures made for oil and gas properties, other than acquisitions. Cash available for distribution will not reflect changes in working capital balances. Cash available for distribution is not a measurement of our financial performance or liquidity under GAAP and should not be considered as an alternative to, or more meaningful than, net income (loss) or net cash provided by or used in operating activities as determined in accordance with GAAP or as indicators of our financial performance and liquidity. The GAAP measures most directly comparable to cash available for distribution are net income (loss) and net cash provided by operating activities. Cash available for distribution should not be considered as an alternative to, or more meaningful than, net income (loss) or net cash provided by operating activities.

You should not infer from our presentation of Adjusted EBITDAX that its results will be unaffected by unusual or non-recurring items. You should not consider Adjusted EBITDAX or cash available for distribution in isolation or as a substitute for analysis of our results as reported under GAAP. Additionally, because Adjusted EBITDAX and cash available for distribution may be defined differently by other companies in our industry, our definition of Adjusted EBITDAX and cash available for distribution may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Reconciliation of Adjusted EBITDAX and Cash Available for Distribution to GAAP Financial Measures

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
	(in thousands)			
Net (loss) income	$ (32,088)	$ 4,352	$ (45,653)	$ 6,633
Interest expense	5,523	4,505	16,842	10,697
Interest income	(308)	(113)	(604)	(516)
Depreciation, depletion and amortization	24,226	23,697	77,032	66,810
Accretion of discount in asset retirement obligation	3,219	3,982	10,988	11,623
Exploration expense	170	91	404	224
Non-cash derivative (gain) loss	37,328	(7,250)	73,336	(7,094)
Non-cash incentive compensation	3,036	3,468	9,395	12,835
Non-recurring (gain)/loss	$ 222	$ 18	$ (1,313)	$ 23
Adjusted EBITDAX	$ 41,328	$ 32,750	$ 140,427	$ 101,235
Cash Interest expense	(5,180)	(4,167)	(15,822)	(9,853)
Cash Interest income	308	113	604	516
Exploration expense	(170)	(91)	(404)	(224)
Development costs	(38,987)	(21,062)	(63,657)	(36,018)
Cash Available for Distribution	$ (2,701)	$ 7,543	$ 61,148	$ 55,656
Net cash provided by operating activities	$ 33,665	$ 28,271	$ 116,173	$ 85,735
Changes in operating assets and liabilities	2,621	334	8,632	5,939
Development costs	(38,987)	(21,062)	(63,657)	(36,018)
Cash Available for Distribution	$ (2,701)	$ 7,543	$ 61,148	$ 55,656

Results of Operations

Three Months Ended September 30, 2026 Compared to the Three Months Ended September 30, 2025

	Three months ended September 30,	
	2026	2025
REVENUES		
Oil and condensate	$ 29,845	$ 66,330
Natural gas liquids	10,212	7,504
Natural gas	15,036	27,042
Total Revenues	55,093	100,876
EXPENSES		
Production	43,698	47,864
Exploration	170	91
Taxes, transportation and other	18,437	16,648
Depreciation, depletion and amortization	24,226	23,697
Accretion of discount in asset retirement obligation	3,219	3,982
General and administrative	3,936	4,834
Total Expenses	93,686	97,116
OPERATING (LOSS) INCOME	(38,593)	3,760
OTHER INCOME (EXPENSE)		
Other income	11,720	4,984
Interest income	308	113
Interest expense	(5,523)	(4,505)
Total Other Income	6,505	592
NET (LOSS) INCOME	$ (32,088)	$ 4,352

The following table provides a summary of our sales volumes, average prices (both including and excluding the effects of derivatives, and including the effects of realized derivatives only) and operating expenses on a per Boe basis for the periods indicated:

	Three Months Ended September 30,	
	2026	2025
Sales:		
Oil and condensate sales (MBbls)	1,088	1,053
Natural gas liquids sales (MBbls)	373	387
Natural gas sales (MMcf)	5,227	7,116
Total (MBoe)	2,332	2,626
Total (MBoe/d)	25	29
Average sales prices:		
Oil and condensate excluding the effects of derivatives (per Bbl)	$ 84.20	$ 62.80
Oil and condensate including the effects of realized derivatives (per Bbl) (4)	$ 63.62	$ 62.73
Oil and condensate (per Bbl) (1)	$ 27.43	$ 63.00
Natural gas liquids excluding the effects of derivatives (per Bbl)	$ 27.39	$ 19.34
Natural gas liquids including the effects of realized derivatives (per Bbl) (4)	$ 27.39	$ 19.34
Natural gas liquids (per Bbl) (2)	$ 27.36	$ 19.38
Natural gas excluding the effects of derivatives (per Mcf)	$ 2.14	$ 2.38
Natural gas including the effects of realized derivatives (per Mcf) (4)	$ 2.48	$ 2.82
Natural gas (per Mcf) (3)	$ 2.88	$ 3.80
Expense per Boe:		
Production	$ 18.73	$ 18.23
Taxes, transportation and other	$ 7.90	$ 6.34
Depreciation, depletion and amortization	$ 10.39	$ 9.02
General and administrative expenses	$ 1.69	$ 1.84

(1) Oil and condensate prices include both realized gains and losses and unrealized losses from derivatives. Unrealized losses were $39.4 million for the three months ended September 30, 2026 and unrealized gains were $0.3 million for the three months ended September 30, 2025. Realized losses were $22.4 million for the three months ended September 30, 2026 and $0.1 million for the three months ended September 30, 2025.

(2) Natural gas liquids prices include unrealized gains and losses from derivatives. Unrealized losses were $14.0 thousand for the three months ended September 30, 2026 and unrealized gains were $15.0 thousand for the three months ended September 30, 2025.

(3) Natural gas prices include both realized and unrealized gains from derivatives. Unrealized gains were $2.1 million for the three months ended September 30, 2026 and $6.9 million for the three months ended September 30, 2025. Realized gains were $1.8 million for the three months ended September 30, 2026 and $3.1 million for the three months ended September 30, 2025.
(4) These prices include revenues from customers as well as the effects of realized gains and losses from derivatives and exclude the unrealized gains and losses from derivatives.

Revenues

Revenues decreased $45.8 million, or 45%, from $100.9 million for the three months ended September 30, 2025 to $55.1 million for the three months ended September 30, 2026. Revenue decreased $68.3 million due to the change in results from our hedging activity, from net gains of $10.3 million for the three months ended September 30, 2025 to net losses of $57.9 million for the three months ended September 30, 2026, of which $44.6 million related to the change in unrealized results and $23.7 million related to the change in realized results. Additionally, a 10% decrease in the average selling price of natural gas, excluding the effects of derivatives, resulted in a decrease in revenue of $1.7 million. Finally, revenue decreased $1.5 million due to a decrease in production of 293 MBoe primarily as a result of the sale of Cross Timbers Energy assets and natural decline in the San Juan Basin partially offset by increased production in the Williston Basin and Permian Basin. These decreases were partially offset by increases in the average selling prices, excluding the effects of derivatives, of oil of 34% which resulted in an increase in revenue of $22.5 million and of NGLs of 42% which resulted in an increase in revenue of $3.1 million.

Production expenses

Production expenses decreased $4.2 million, or 9%, from $47.9 million for the three months ended September 30, 2025 to $43.7 million for the three months ended September 30, 2026. The sale of Cross Timbers Energy assets reduced costs by $10.9 million which was largely offset by increased costs related to production from the Williston Basin acquisition and increased maintenance activity.

On a per unit basis, production expenses increased from $18.23 per Boe sold for the three months ended September 30, 2025 to $18.73 per Boe sold for the three months ended September 30, 2026. The increase is primarily related to a decrease in production of 293 MBoe partially offset by decreased costs principally attributable to the Cross Timbers Energy sale.

Taxes, transportation, and other

Taxes, transportation, and other increased $1.8 million, or 11%, from $16.6 million for the three months ended September 30, 2025 to $18.4 million for the three months ended September 30, 2026. The increase is primarily attributable to higher oil and NGL prices partially offset by the decrease in production and lower natural gas prices.

On a per unit basis, taxes, transportation, and other increased from $6.34 per Boe sold for the three months ended September 30, 2025 to $7.90 per Boe sold for the three months ended September 30, 2026. The increase is primarily related to increased costs, a change in production mix and decreased production.

Depreciation, depletion, and amortization

Depreciation, depletion, and amortization (“DD&A”) increased $0.5 million, or 2%, from $23.7 million for the three months ended September 30, 2025 to $24.2 million for the three months ended September 30, 2026. The increase is primarily attributable to the DD&A from increased production associated with the Williston Basin acquisitions of $5.6 million, which has a higher rate than the historical properties partially offset by the sale of Cross Timbers Energy assets and decrease in production in the San Juan Basin.

On a per unit basis, depreciation, depletion, and amortization increased from $9.02 per Boe sold for the three months ended September 30, 2025 to $10.39 per Boe sold for the three months ended September 30, 2026. The increase is primarily related to the production associated with the Williston Basin acquisitions, which has a higher rate than the historical properties.

General and administrative

General and administrative (“G&A”) expenses decreased $0.9 million, or 19%, from $4.8 million for the three months ended September 30, 2025 to $3.9 million for the three months ended September 30, 2026. The decrease is primarily attributable to lower professional fees.

On a per unit basis, G&A expense decreased from $1.84 per Boe sold for the three months ended September 30, 2025 to $1.69 per Boe sold for the three months ended September 30, 2026. The decrease is primarily related to decreased costs partially offset by decreased production.

Other income

Other income increased $6.7 million, or 135%, from $5.0 million for the three months ended September 30, 2025 to $11.7 million for the three months ended September 30, 2026. The increase is primarily attributable to higher CO_2 and plant income of $4.1 million due to the absence of third-party pipeline disruptions and lease bonus on term lease assignment of $2.0 million. The CO_2 and plant income is ancillary to the operations of the gas processing plant in the Permian Basin in New Mexico and CO_2 assets in Colorado.

Interest expense

Interest expense increased $1.0 million, or 23%, from $4.5 million for the three months ended September 30, 2025 to $5.5 million for the three months ended September 30, 2026. The increase is primarily attributable to increased borrowings partially offset by a lower average interest rate.

Nine Months Ended September 30, 2026 Compared to the Nine Months Ended September 30, 2025

	Nine Months Ended September 30,	
	2026	2025
REVENUES		
Oil and condensate	$ 157,857	$ 190,379
Natural gas liquids	30,308	23,958
Natural gas	46,076	60,743
Total Revenues	234,241	275,080
EXPENSES		
Production	132,888	133,469
Exploration	404	224
Taxes, transportation and other	57,907	49,763
Depreciation, depletion and amortization	77,032	66,810
Accretion of discount in asset retirement obligation	10,988	11,623
General and administrative	13,501	16,729
Total Expenses	292,720	278,618
OPERATING (LOSS) INCOME	(58,479)	(3,538)
OTHER INCOME (EXPENSE)		
Other income	29,064	20,352
Interest income	604	516
Interest expense	(16,842)	(10,697)
Total Other Income	12,826	10,171
NET (LOSS) INCOME	$ (45,653)	$ 6,633

The following table provides a summary of our sales volumes, average prices (both including and excluding the effects of derivatives, and including the effects of realized derivatives only) and operating expenses on a per Boe basis for the periods indicated:

	Nine Months Ended September 30,	
	2026	2025
Sales:		
Oil and condensate sales (MBbls)	3,604	2,829
Natural gas liquids sales (MBbls)	1,185	1,050
Natural gas sales (MMcf)	18,269	20,657
Total (MBoe)	7,834	7,322
Total (MBoe/d)	29	27
Average sales prices:		
Oil and condensate excluding the effects of derivatives (per Bbl)	$ 82.89	$ 64.22
Oil and condensate including the effects of realized derivatives (per Bbl) (4)	$ 66.45	$ 64.94
Oil and condensate (per Bbl) (1)	$ 43.80	$ 67.30
Natural gas liquids excluding the effects of derivatives (per Bbl)	$ 25.55	$ 22.79
Natural gas liquids including the effects of realized derivatives (per Bbl) (4)	$ 25.55	$ 22.79
Natural gas liquids (per Bbl) (2)	$ 25.57	$ 22.81
Natural gas excluding the effects of derivatives (per Mcf)	$ 2.08	$ 2.60
Natural gas including the effects of realized derivatives (per Mcf) (4)	$ 2.07	$ 2.92
Natural gas (per Mcf) (3)	$ 2.52	$ 2.94
Expense per Boe:		
Production	$ 16.96	$ 18.23
Taxes, transportation and other	$ 7.39	$ 6.80
Depreciation, depletion and amortization	$ 9.83	$ 9.12
General and administrative expenses	$ 1.72	$ 2.28

(1) Oil and condensate prices include both realized and unrealized gains and losses from derivatives. Unrealized losses were $81.6 million for the nine months ended September 30, 2026 and unrealized gains were $6.7 million for the nine months ended September 30, 2025. Realized losses were $59.2 million for the nine months ended September 30, 2026 and realized gains were $2.0 million for the nine months ended September 30, 2025.

(2) Natural gas liquids prices include unrealized gains from derivatives. Unrealized gains were $25 thousand for the nine months ended September 30, 2026 and $14 thousand for the nine months ended September 30, 2025.

(3) Natural gas prices include both realized gains and losses and unrealized gains from derivatives. Unrealized gains were $8.3 million for the nine months ended September 30, 2026 and $0.4 million for the nine months ended September 30, 2025. Realized losses were $0.2 million for the nine months ended September 30, 2026 and realized gains were $6.6 million for the nine months ended September 30, 2025.

(4) These prices include revenues from customers as well as the effects of realized gains and losses from derivatives and exclude the unrealized gains and losses from derivatives.

Revenues

Revenues decreased $40.8 million, or 15%, from $275.1 million for the nine months ended September 30, 2025 to $234.2 million for the nine months ended September 30, 2026. The decrease was primarily attributable to the change in results from our hedging activity of $148.4 million, from net gains of $15.7 million for the nine months ended September 30, 2025 to net losses of $132.8 million for the nine months ended September 30, 2026, of which $80.4 million related to the change in unrealized results and $68.0 million related to the change in realized results. Additionally, a 20% decrease in the average selling price of natural gas, excluding the effects of derivatives, resulted in a decrease in revenue of $10.8 million. These decreases were partially offset by a 512 MBoe increase in production which resulted in a $62.7 million increase in revenue primarily as a result of the acquisition of producing assets in the Williston Basin and new wells drilled under our capital program, partially offset by the sale of Cross Timbers Energy assets and natural declines in the San Juan Basin. Also, increases in the average selling prices, excluding the effects of derivatives, of oil of 29% and NGLs of 12% resulted in increases in revenue of $52.8 million on oil and $2.9 million on NGLs.

Production expenses

Production expenses decreased $0.6 million, or less than 1%, from $133.5 million for the nine months ended September 30, 2025 to $132.9 million for the nine months ended September 30, 2026. The sale of Cross Timbers Energy assets reduced costs by $19.1 million, which was largely offset by increased costs related to production from the Williston Basin acquisition and increased maintenance activity.

On a per unit basis, production expenses decreased from $18.23 per Boe sold for the nine months ended September 30, 2025 to $16.96 per Boe sold for the nine months ended September 30, 2026. The decrease is primarily related to decreased costs principally attributable to the Cross Timbers Energy sale and an increase in production of 512 MBoe.

Taxes, transportation, and other

Taxes, transportation, and other increased $8.1 million, or 16%, from $49.8 million for the nine months ended September 30, 2025 to $57.9 million for the nine months ended September 30, 2026. The increase is primarily attributable to the increase in production, as well as an increase in oil and NGL prices, partially offset by decreased natural gas prices.

On a per unit basis, taxes, transportation, and other increased from $6.80 per Boe sold for the nine months ended September 30, 2025 to $7.39 per Boe sold for the nine months ended September 30, 2026. The increase is primarily attributable to increased costs partially offset by increased production.

Depreciation, depletion, and amortization

Depreciation, depletion, and amortization increased $10.2 million, or 15%, from $66.8 million for the nine months ended September 30, 2025 to $77.0 million for the nine months ended September 30, 2026. The increase is attributable to the DD&A from increased production associated with the Williston Basin acquisitions of $22.6 million, which has a higher rate than the historical properties partially offset by the Cross Timbers Energy sale and decreased production in the San Juan Basin.

On a per unit basis, depreciation, depletion, and amortization increased from $9.12 per Boe sold for the nine months ended September 30, 2025 to $9.83 per Boe sold for the nine months ended September 30, 2026. The increase is primarily related to the production associated with the Williston Basin acquisitions, which has a higher rate than the historical properties.

General and administrative

General and administrative ("G&A") expenses decreased $3.2 million, or 19%, from $16.7 million for the nine months ended September 30, 2025 to $13.5 million for the nine months ended September 30, 2026. The decrease is primarily attributable to lower personnel costs of $2.5 million and lower professional fees.

On a per unit basis, G&A expense decreased from $2.28 per Boe sold for the nine months ended September 30, 2025 to $1.72 per Boe sold for the nine months ended September 30, 2026. The decrease is primarily related to decreased costs and increased production.

Other income

Other income increased $8.7 million, or 43%, from $20.4 million for the nine months ended September 30, 2025 to $29.1 million for the nine months ended September 30, 2026. The increase is primarily attributable to increased marketing income of $2.2 million, $2.1 million in bonus payments on term assignment of leases, higher CO_2 and plant income of $2.0 million and the $1.4 million gain on sale of Cross Timbers Energy assets. The CO_2 and plant income is ancillary to the operations of the gas processing plant in the Permian Basin in New Mexico and CO_2 assets in Colorado.

Interest expense

Interest expense increased $6.1 million, or 57%, from $10.7 million for the nine months ended September 30, 2025 to $16.8 million for the nine months ended September 30, 2026. The increase is primarily attributable to the increased borrowings and amortization of capitalized loan costs partially offset by a lower average interest rate.

Liquidity and Capital Resources

Our primary sources of liquidity and capital will be cash flows generated by operating activities and borrowings under our Credit Facility. Outstanding borrowings under our Credit Facility were $264.0 million at September 30, 2026 and $284.0 million at December 31, 2025, and the remaining availability under our Credit Facility was $146.0 million at September 30, 2026 and $126.0 million at December 31, 2025. Additionally, we had negative net working capital (including cash and excluding the effects of derivative instruments) of $14.4 million at September 30, 2026 and negative net working capital of $71.8 million at December 31, 2025. The negative working capital of $71.8 million at December 31, 2025 is primarily related to the $70.0 million deferred payment on the WRE Acquisition that was due July 31, 2026.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to our unitholders. Our quarterly cash distributions may vary from quarter to quarter as a direct result of variations in the performance of our

business, including those caused by fluctuations in the prices of oil and natural gas. Such variations may be significant and quarterly distributions paid to our unitholders may be zero. Our third quarter distribution of $0.44 per unit with respect to cash available for distribution for the three months ended September 30, 2026, was declared on November 3, 2026 and will be paid on November 20, 2026 to unitholders of record on November 13, 2026.

Our acquisition and development expenditures consist of acquisitions of proved, unproved and other property and development expenditures offset by sales of properties. Our capital expenditures including acquisitions and dispositions resulted in cash provided by investing activities of $34.0 million for the nine months ended September 30, 2026 and cash used by investing activities of $305.4 million for the nine months ended September 30, 2025. Included in investing activities in the nine months ended September 30, 2026 are $101.3 million of proceeds from the sale of properties.

In order to mitigate volatility in oil and natural gas prices, we have entered into commodity derivative contracts. See "Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk."

We incurred costs of approximately $79.2 million for drilling, completion and recompletion activities and facilities costs in the nine months ended September 30, 2026 and we expect to spend approximately $90.0 million to $95.0 million for such costs in 2026.

The amount and timing of these capital expenditures is substantially within our control and subject to management's discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including, but not limited to the prevailing and anticipated prices for oil, NGLs and natural gas, the availability of necessary equipment, infrastructure and capital, seasonal conditions and drilling and acquisition costs. Any postponement or elimination of our development program could result in a reduction of proved reserve volumes, production and cash flow, including distributions to unitholders.

Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our distributions, meet our debt obligations and fund our 2026 capital development programs from cash flow from operations and borrowings under our Credit Facility.

If cash flow from operations does not meet our expectations, we may reduce our expected level of capital expenditures and/or distributions to unitholders. Alternatively, we may fund these expenditures using borrowings under our Credit Facility, issuances of debt and equity securities or from other sources, such as asset sales. We cannot assure you that necessary capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by covenants in our debt arrangements. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us, finance the capital expenditures necessary to maintain our production or proved reserves, or make distributions to unitholders.

Cash flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	Nine Months Ended September 30,	
	2026	2025
Net cash provided by operating activities	$ 116,173	$ 85,735
Net cash provided by (used by) investing activities	33,999	(305,432)
Net cash (used by) provided by financing activities	(150,913)	217,700

Nine Months Ended September 30, 2026 Compared to Nine Months Ended September 30, 2025

Net cash provided by operating activities

Net cash provided by operating activities increased $30.4 million for the nine months ended September 30, 2026 compared to the nine months ended September 30, 2025 due to improved operating results, excluding the effects of derivatives, primarily due to increased revenues partially offset by increased costs.

Net cash provided by (used by) investing activities

Net cash from investing activities increased $339.4 million, from net cash used of $305.4 million for the nine months ended September 30, 2025 to net cash provided of $34.0 million for the nine months ended September 30, 2026, primarily due to proceeds from the sale of the Cross Timbers Energy assets of $101.3 million and a decrease in proved property acquisitions of $267.1 million, partially offset by increased development costs of $27.6 million.

Net cash (used by) provided by financing activities

	Nine Months Ended September 30,	
	2026	2025
	(in thousands)	
Proceeds from long-term debt	$ 86,000	$ 360,500
Payments on long-term debt	(106,000)	(246,500)
Net proceeds from public offering	—	189,502
Proceeds from sale of units to cover withholding taxes	2,173	1,215
Withholding taxes paid on vesting of restricted units	(2,120)	(2,358)
Debt issuance costs	(85)	(2,429)
Hedge financing cost	(2,126)	—
Payment of deferred acquisition cost	(70,000)	—
Distributions	(58,755)	(82,230)
Net cash (used by) provided by financing activities	$ (150,913)	$ 217,700

Net cash from financing activities decreased $368.6 million, from net cash provided of $217.7 million for the nine months ended September 30, 2025 to net cash used of $150.9 million for the nine months ended September 30, 2026, primarily due to a decrease in net proceeds from public offering of $189.5 million, decreased net borrowings under our Credit Facility of $134.0 million and payment of deferred acquisition cost of $70.0 million, partially offset by decreased distributions to unitholders of $23.5 million.

Revolving credit agreement

On July 31, 2025, we entered into Amendment No. 5 to our Credit Facility with certain commercial banks, as the lenders, and JPMorgan Chase Bank, N.A., as the administrative agent. We use the Credit Facility for general corporate purposes. Amendment No. 5 increased the borrowing base from $275 million to $410 million, extended the maturity date to August 30, 2029 and joined certain new Lenders to the Credit Facility.

Our Credit Facility contains certain customary representations, warranties and covenants, including but not limited to, limitations on incurring debt and liens, limitations on merging or consolidating with another company, limitations on making certain restricted payments, limitations on investments, limitations on paying distributions on, redeeming, or repurchasing common units, limitations on entering into transactions with affiliates, and limitations on asset sales. The Credit Facility also contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Credit Facility to be immediately due and payable.

At our election, interest on borrowings under the credit facility is determined by reference to either the secured overnight financing rate ("SOFR") plus an applicable margin between 3.00% and 4.00% per annum (depending on the then-current level of borrowings under the Credit Facility) or the alternate base rate ("ABR") plus an applicable margin between 2.00% and 3.00% per annum (depending on the then-current level of borrowings under the Credit Facility). The weighted average interest rate on Credit Facility borrowings was 7.4% in the nine months ended September 30, 2026.

We are required to maintain (i) a current ratio (the ratio of current assets to current liabilities) greater than 1.0 to 1.0, which for purposes of this definition includes availability under the Credit Facility but excludes the fair value of derivative instruments, and (ii) a ratio of total net debt-to-EBITDAX of not greater than 3.0 to 1.0. For purposes of the total net debt-to-EBITDAX ratio, total net debt is total debt for borrowed money (including capital leases and purchase money debt) minus unrestricted cash and cash equivalents on hand at such time (not exceeding $15.0 million in the aggregate), minus the unpaid balance of the FAM Loan. EBITDAX means the sum of (i) net income plus interest expense; income taxes paid; depreciation, depletion and amortization; exploration expenses, including workover expenses; non-cash charges including unrealized losses on derivative instruments; and, any extraordinary or non-recurring charges, minus (ii) any extraordinary or non-recurring income and any non-cash income including unrealized gains on derivative instruments. Effective with the completion of the spring redetermination in June 2026, we received a waiver of all hedge requirements for months 19 through 24 for the quarters ended June 30, 2026 and September 30, 2026. Under the terms of the Credit Facility, we were in compliance with all of our debt covenants as of September 30, 2026. Additionally, we believe we have adequate liquidity to continue as a going concern for at least the next twelve months from the date of this report.

We had $264.0 million debt outstanding and $146.0 million available under our Credit Facility as of September 30, 2026.

Contractual obligations and commitments

We have not guaranteed the debt or obligations of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in consolidated debt or losses.

Derivative contracts

We have entered into derivative instruments to hedge our exposure to commodity price fluctuations. If market prices are higher than the contract prices when the cash settlement amount is calculated, we are required to pay the contract counterparties. As of September 30, 2026, the current liability related to such contracts was $54.5 million and the long-term liability related to such contracts was $11.3 million. Such payments will generally be funded by higher prices received from the sale of oil, NGLs and natural gas. For further information on derivative contracts, see Note 10 in the financial statements included elsewhere in this Quarterly Report.

Asset Retirement Obligation

At September 30, 2026, we had asset retirement obligations of $161.2 million inclusive of a current portion of $2.0 million. For further information on asset retirement obligations, see Note 7 in the financial statements included elsewhere in this Quarterly Report.

Critical Accounting Policies

There has been no change in our critical accounting policies from those disclosed in our Annual Report on Form 10-K filed with the SEC on February 26, 2026.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. Also, gains and losses on these instruments are generally offset by losses and gains on the offsetting expenses.

Commodity price risk

Our major market risk exposure is in the pricing that we receive for our oil, NGL and natural gas production. Pricing for oil, NGLs, and natural gas has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil, NGL, and natural gas production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

To reduce the impact of fluctuations in oil, NGL and natural gas prices on our revenues, we periodically enter into commodity derivative contracts with respect to certain of our oil, NGL and natural gas production through various transactions that limit the risks of fluctuations of future prices. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling. These hedging activities are intended to limit our exposure to product price volatility and to maintain stable cash flows.

As of September 30, 2026, the fair market value of our oil, NGL and natural gas derivative contracts was a net liability of $52.5 million. Based upon our open commodity derivative positions at September 30, 2026, a hypothetical 10% change in the NYMEX WTI, Henry Hub prices, OPIS prices and basis prices would change our net oil, NGL and natural gas derivative liability by approximately $35.3 million.

(in thousands)	Fair Value at September 30, 2026	Hypothetical Price Increase or Decrease of 10% Price Change
Derivative asset (liability) – Crude Oil	$ (57,715)	$ 29,406
Derivative asset (liability) – Natural Gas Liquids	$ 44	$ 34
Derivative asset (liability) – Natural Gas	$ 5,221	$ 5,821
Net derivative liability	$ (52,450)	$ 35,261

The hypothetical change in fair value could be a gain or loss depending on whether prices increase or decrease.

Counterparty and customer credit risk

Our cash and cash equivalents are exposed to concentrations of credit risk. We manage and control this risk by investing these funds in major financial institutions. We often have balances in excess of the federally insured limits.

We sell oil, NGL and natural gas production to various types of customers. Credit is extended based on an evaluation of the customer's financial condition and historical payment record. The future availability of a ready market for our production depends on numerous factors outside of our control, none of which can be predicted with certainty. For the year ended December 31, 2025, we had three customers, and for the year ended December 31, 2024, we had two customers, that each accounted for more than 10% of total revenues. We do not believe the loss of any single purchaser would materially impact our operating results because oil, NGLs and natural gas are fungible products with well-established markets and numerous purchasers.

At September 30, 2026, we had commodity derivative contracts with counterparties. We are currently not required to provide collateral or other security to counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Additionally, we use master netting arrangements to minimize credit risk exposure. The creditworthiness of our counterparties is subject to periodic review.

Interest rate risk

At September 30, 2026, we had $264.0 million of variable rate debt outstanding. Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $2.6 million per year. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement."

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including the Co-Chief Executive Officer and Chief Financial Officer, along with the Co-Chief Executive Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act as of September 30, 2026. Based on this evaluation, the Co-Chief Executive Officer and Chief Financial Officer, along with the Co-Chief Executive Officer concluded that as of September 30, 2026, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Exchange Act is recorded, processed, summarized, and reported as and when required, and that such information is accumulated and communicated to our management, including the Co-Chief Executive Officer and Chief Financial Officer, along with the Co-Chief Executive Officer, to allow timely decisions regarding its required disclosure. Based on the evaluation of our disclosure controls and procedures as of September 30, 2026, the Co-Chief Executive Officer and Chief Financial Officer, along with the Co-Chief Executive Officer have concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2026 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II - Other Information

Item 1. Legal Proceedings

We are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuits with certainty, but management believes it is remote that pending or threatened legal matters will have a material adverse impact on our financial condition. Due to the nature of our business, we are, from time to time, involved in other routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment-related disputes. In the opinion of our management, none of these other pending litigation matters, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

Item 1A. Risk Factors

There have been no material changes in the risk factors disclosed under Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2025.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

During the fiscal quarter ended September 30, 2026, there were no adoptions, modifications, or terminations by directors or officers of Rule 10b5-1 trading arrangements or non-Rule 10b5-1 trading arrangements, each as defined in Item 408 of Regulation S-K.

Item 6. Exhibits

Exhibit Number	Description
3.1	Amended and Restated Certificate of Limited Partnership of TXO Partners, L.P. (incorporated by reference to Exhibit 3.1 to Quarterly Report on Form 10-Q filed on May 9, 2023)
3.2	Amended and Restated Certificate of Formation of TXO Partners, GP, LLC (incorporated by reference to Exhibit 3.2 to Quarterly Report on Form 10-Q filed on May 9, 2023)
3.3	Seventh Amended and Restated Agreement of Limited Partnership of TXO Partners, L.P. (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K filed on January 31, 2023)
3.4	Amendment No. 1 to the Seventh Amended and Restated Agreement of Limited Partnership of TXO Partners, L.P. (incorporated by reference to Exhibit 3.3 to Quarterly Report on Form 10-Q filed on May 9, 2023)
3.5	Amended and Restated Limited Liability Company Agreement of TXO Partners GP, LLC (incorporated by reference to Exhibit 3.4 to Annual Report on Form 10-K filed on March 31, 2023)
3.6	Amendment No. 1 to the Amended and Restated Limited Liability Company Agreement of TXO Partners GP, LLC (incorporated by reference to Exhibit 3.4 to Quarterly Report on Form 10-Q filed on May 9, 2023)
31.1*	Certification of Co-Chief Executive Officer pursuant to Exchange Act Rule 13a-14(a) and Rule 15d-14(a)
31.2*	Certification of Co-Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act Rule 13a-14(a) and Rule 15d-14(a)
32.1*	Certification of Co-Chief Executive Officer pursuant to 18 U.S.C. Section 1350
32.2*	Certification of Co-Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
101.INS	Inline XBRL Instance Document (the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document).
101.SCH	Inline XBRL Taxonomy Extension Schema with Embedded Linkbase Documents
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)

* Filed herewith

SIGNATURES

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

TXO Partners, L.P.

Date: November 3, 2026

By: TXO Partners GP, LLC, its general partner

By: /s/ Brent W. Clum

Name: Brent W. Clum
Title: Co-Chief Executive Officer, Chief Financial Officer and Duly Authorized Officer

Exhibit 31.1

CERTIFICATION PURSUANT TO
RULES 13a-14(a) AND 15d-14(a) UNDER THE SECURITIES EXCHANGE ACT OF 1934,
AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Gary D. Simpson, certify that:

(1) I have reviewed this Quarterly Report on Form 10-Q of TXO Partners, L.P.;

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

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

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

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

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

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

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

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

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

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

Date: November 3, 2026

By: /s/ Gary D. Simpson
Gary D. Simpson
Co-Chief Executive Officer
TXO Partners GP, LLC, its general partner

Exhibit 31.2

CERTIFICATION PURSUANT TO
RULES 13a-14(a) AND 15d-14(a) UNDER THE SECURITIES EXCHANGE ACT OF 1934,
AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Brent W. Clum, certify that:

(1) I have reviewed this Quarterly Report on Form 10-Q of TXO Partners, L.P.;

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

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

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

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

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

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

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

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

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

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

Date: November 3, 2026

By: /s/ Brent W. Clum

Brent W. Clum
Co-Chief Executive Officer and Chief Financial Officer
TXO Partners GP, LLC, its general partner

Exhibit 32.1

Pursuant to 18 U.S.C. § 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned officer of TXO Partners, L.P. (the "***Partnership***") hereby certifies, to such officer's knowledge, that:

(i) the Quarterly Report on Form 10-Q of the Partnership for the fiscal quarter ended September 30, 2026 (the "***Report***") fully complies with the requirements of Section 13(a) or Section 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 3, 2026

By: /s/ Gary D. Simpson

Gary D. Simpson
Co-Chief Executive Officer
TXO Partners GP, LLC, its general partner

The foregoing certification is being furnished solely to accompany the Report pursuant to 18 U.S.C. § 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not to be incorporated by reference into any filing of the Partnership, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 32.2

Pursuant to 18 U.S.C. § 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned officer of TXO Partners, L.P. (the "***Partnership***") hereby certifies, to such officer's knowledge, that:

(i) the Quarterly Report on Form 10-Q of the Partnership for the fiscal quarter ended September 30, 2026 (the "***Report***") fully complies with the requirements of Section 13(a) or Section 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 3, 2026

By: /s/ Brent W. Clum

Brent W. Clum
Co-Chief Executive Officer and Chief Financial Officer
TXO Partners GP, LLC, its general partner

The foregoing certification is being furnished solely to accompany the Report pursuant to 18 U.S.C. § 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not to be incorporated by reference into any filing of the Partnership, whether made before or after the date hereof, regardless of any general incorporation language in such filing.