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

FORM 8-K/A

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

Date of Report (Date of earliest event reported): August 30, 2024

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

Delaware	001-41605	32-0368858
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS 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

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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 representing limited partner interests	TXO	New York Stock Exchange

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

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. ☐

EXPLANATORY NOTE

This Current Report on Form 8-K/A of TXO Partners L.P. (the "Partnership"), amends and supplements the Current Report on Form 8-K of the Partnership, dated August 30, 2024 and filed with the Securities and Exchange Commission on August 30, 2024 (the "Initial Form 8-K"), which reported under Item 2.01 that on August 30, 2024, the Partnership and its wholly-owned subsidiary, Morningstar Operating LLC, closed the previously announced acquisition of certain producing oil and gas assets located in the Williston Basin of Montana and North Dakota from Eagle Mountain Energy Partners, LLC, a Delaware limited liability company ("EMEP"), and VR4-ELM, LP, a Texas limited partnership ("Vendera" and together with EMEP, the "EMEP Sellers"), pursuant to that certain Purchase and Sale Agreement, dated as of June 25, 2024, by and among the Partnership, Morningstar Operating LLC and the EMEP Sellers (the "Transactions").

This amendment is filed to provide the financial statements of the businesses acquired in the Transactions and the pro forma financial information of the Partnership for the Transactions as required by Item 9.01 of Form 8-K. Except as set forth below, the Initial Form 8-K is unchanged.

Item 9.01 Financial Statements and Exhibits.

(a) Financial Statements of Business Acquired.

The unaudited consolidated financial statements of EMEP for the six months ended June 30, 2024 and 2023, including the related notes thereto, are filed herewith as Exhibit 99.1.

The audited consolidated financial statements of EMEP for the years ended December 31, 2023 and 2022, including the related notes thereto, are filed herewith as Exhibit 99.2.

The unaudited statements of revenues and direct operating expenses of the Vendera properties for the six months ended June 30, 2024 and 2023, including the related notes thereto, are filed herewith as Exhibit 99.3.

The audited statements of revenues and direct operating expenses of the Vendera properties for the years ended December 31, 2023 and 2022, including the related notes thereto, are filed herewith as Exhibit 99.4.

(b) Pro Forma Financial Information.

The unaudited pro form condensed combined balance sheet of the Partnership as of June 30, 2024, and the unaudited pro forma condensed combined statements of operations of the Partnership for the six months ended June 30, 2024 and the year ended December 31, 2023, including the related notes thereto, giving effect to the Transactions are filed herewith as Exhibit 99.5. The unaudited pro forma financial information gives effect to the Transactions on the basis, and subject to the assumptions, set forth in accordance with Article 11 of Regulation S-X.

(d) Exhibits.

Exhibit Number	Description
23.1	Consent of KPMG LLP (Eagle Mountain Energy Partners, LLC).
23.2	Consent of KPMG LLP (Vendera Properties).
99.1	Unaudited Consolidated Financial Statements of Eagle Mountain Energy Partners, LLC for the six months ended June 30, 2024 and 2023.
99.2	Audited Consolidated Financial Statements of Eagle Mountain Energy Partners, LLC for the years ended December 31, 2023 and 2022.
99.3	Unaudited Statements of Revenues and Direct Operating Expenses of the Vendera Properties for the six months ended June 30, 2024 and 2023.
99.4	Audited Statements of Revenues and Direct Operating Expenses of the Vendera Properties for the years ended December 31, 2023 and 2022.
99.5	Unaudited Pro Forma Condensed Combined Financial Information of TXO Partners, L.P as of and for the six months ended June 30, 2024 and for the year ended December 31, 2023.
104	Cover Page Interactive Data File (embedded within the Inline XBRL document).

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 hereunto duly authorized.

TXO Partners, L.P.

By: TXO Partners GP, LLC its general partner

Dated: November 13, 2024

By: /s/ Brent W. Clum
Name: Brent W. Clum
Title: President of Business Operations and
Chief Financial Officer

Exhibit 23.1

Consent of Independent Auditors

We consent to the incorporation by reference in the registration statements (Nos. 333-281885 and 333-277671) on Form S-3 and (No. 333-271045) on Form S-8 of TXO Partners, L.P. of our reports dated November 13, 2024, with respect to the consolidated financial statements of Eagle Mountain Energy Partners, L.L.C. and subsidiaries, which reports appear in the Form 8-K/A of TXO Partners, L.P. dated November 13, 2024.

/s/ KPMG LLP

Dallas, Texas
November 13, 2024

Exhibit 23.2

Consent of Independent Auditors

We consent to the incorporation by reference in the registration statements (Nos. 333-281885 and 333-277671) on Form S-3 and (No. 333-271045) on Form S-8 of TXO Partners, L.P. of our reports dated November 13, 2024, with respect to the consolidated financial statements of Eagle Mountain Energy Partners, L.L.C. and subsidiaries, which reports appear in the Form 8-K/A TXO Partners, L.P. dated November 13, 2024.

/s/ KPMG LLP

Dallas, Texas
November 13, 2024

EAGLE MOUNTAIN ENERGY PARTNERS LLC

Consolidated Financials Statements

For the Six Months Ended June 30, 2024 and 2023

Eagle Mountain Energy Partners LLC
Balance Sheets

(in thousands)	June 30, 2024 (Unaudited)	December 31, 2023
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 4,414	$ 1,594
Accounts receivable, net	11,081	9,015
Derivative fair value	—	1,451
Other	1,566	818
Total Current Assets	17,061	12,878
Property and Equipment, at cost – full-cost method:		
Proved properties	202,885	183,253
Other	188	41
Total Property and Equipment	203,073	183,294
Accumulated depreciation, depletion and amortization	(55,151)	(35,503)
Net Property and Equipment	147,922	147,791
Other Assets:		
Derivative fair value	—	929
Other assets	1,527	997
Total Other Assets	1,527	1,926
TOTAL ASSETS	$ 166,510	$ 162,595
LIABILITIES AND MEMBERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 18,263	$ 11,374
Accrued liabilities	11,071	6,344
Derivative fair value	—	3,575
Other current liabilities	273	166
Total Current Liabilities	29,607	21,459
Long-term Debt	48,400	48,400
Other Liabilities:		
Asset retirement obligation	7,382	7,150
Derivative fair value	—	—
Other liabilities	743	132
Total Other Liabilities	8,125	7,282
Commitments and Contingencies		
Members' Equity:		
Members' equity	80,378	85,454
TOTAL LIABILITIES AND MEMBERS' EQUITY	$ 166,510	$ 162,595

Eagle Mountain Energy Partners LLC
Statements of Income (Unaudited)

(in thousands)	Six months ended June 30, 2024	Six months ended June 30, 2023
REVENUES		
Oil and condensate	$34,777	$29,464
Natural gas liquids	1,850	1,894
Natural gas	134	701
Gain (loss) on derivatives	(8,428)	5,861
Total Revenues	28,333	37,920
EXPENSES		
Production	8,979	8,310
Taxes, transportation and other	2,966	3,073
Depreciation, depletion and amortization	9,372	7,188
Impairment of long-lived assets	10,276	—
Accretion of discount in asset retirement obligation	232	225
General and administrative	(901)	(1,380)
Total Expenses	30,924	17,416
OPERATING (LOSS) INCOME	(2,591)	20,504
OTHER INCOME (EXPENSE)		
Other income	58	8
Interest expense	(2,437)	(2,059)
Total Other Expense	(2,379)	(2,051)
NET (LOSS) INCOME BEFORE INCOME TAX	(4,970)	18,453
State income taxes	106	322
NET (LOSS) INCOME	$ (5,076)	$18,131

Eagle Mountain Energy Partners LLC
Statements of Changes in Members' Equity (Unaudited)

(in thousands)	Six months ended June 30, 2024	2023
Beginning balance, January 1	$ 85,454	$ 68,582
Net (loss) income	(5,076)	18,131
Ending balance, June 30	$ 80,378	$ 86,713

Eagle Mountain Energy Partners LLC
Statements of Cash Flows (Unaudited)

(in thousands)	Six months ended June 30, 2024	2023
OPERATING ACTIVITIES		
Net (loss) income	$ (5,076)	$ 18,131
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation, depletion and amortization	9,372	7,188
Impairment of long-lived assets	10,276	—
Accretion of discount in asset retirement obligation	232	225
Non-cash derivative (gain) loss	8,428	(5,861)
Net cash (paid) received for derivatives	(7,423)	(1,287)
Amortization of deferred financing fees	170	170
Other non-cash items	10	31
Changes in operating assets and liabilities *(a)*	3,692	(1,260)
Cash Provided by Operating Activities	19,681	17,337
INVESTING ACTIVITIES		
Proceeds from sale of property and equipment	—	2,350
Proved property acquisitions	(6)	(19,650)
Development costs	(14,391)	(9,456)
Other property and asset additions	(148)	—
Payments on contingent consideration	(2,200)	(2,200)
Cash Used in Investing Activities	(16,745)	(28,956)
FINANCING ACTIVITIES		
Proceeds from long-term debt	—	22,600
Payments on long-term debt	—	(13,000)
Payments on finance leases	(116)	(161)
Cash Provided by (Used in) Financing Activities	(116)	9,439
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,820	(2,180)
Cash and Cash Equivalents, beginning of period	1,594	7,202
Cash and Cash Equivalents, end of period	$ 4,414	$ 5,022

(a) **Changes in Operating Assets and Liabilities**		
Accounts receivable	$ (2,065)	$ (1,034)
Other current assets	(748)	(164)
Current liabilities	6,505	(62)
	$ 3,692	$ (1,260)

1. Organization and Summary of Significant Accounting Policies

The accompanying financial statements represent EMEP's approximately 88% share of the EMEP Properties (as defined below). EMEP is a Delaware limited liability company ("LLC") formed on January 10, 2020, and is engaged in the exploration, development, production and sale of crude oil and natural gas primarily in Montana and North Dakota. Its executive offices are located in Houston, Texas.

As an LLC, the amount of loss at risk for each individual member is limited to the amount of capital contributed to the LLC and, unless otherwise noted, the individual member's liability for indebtedness of an LLC is limited to the member's actual capital contribution.

The accompanying consolidated financial statements include the financial statements of EMEP and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

Basis of Presentation

The accounts of EMEP are presented in the accompanying financial statements. These financial statements have been prepared in accordance with U.S. GAAP and on the same basis as our audited financial statements as of December 31, 2023. The consolidated balance sheet as of June 30, 2024 and the consolidated statements of operations, members' equity 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. 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.

Impariment

During the six months ended June 30, 2024, EMEP recognized an impairment of long lived assets of $10.3 million, primarily due to a significant increase in future development costs included in the depletable base of proved reserves as well as a decrease in crude oil prices. During the six months ended June 30, 2023, EMEP did not recognize an impairment of long-lived assets.

Sale of Properties

On August 30, 2024, MorningStar Operating LLC completed the acquisition from a wholly-owned subsidiary of EMEP andVR4-ELM, LP, a Texas limited partnership ("Vendera" and together with EMEP, the "EMEP Entities") of producing properties in the Greater Williston Basin of Montana and North Dakota (the "EMEP Properties") for cash consideration of $241.8 million and 2.5 million common units of TXO valued at $50.0 million, subject to customary purchase price adjustments.

2. Debt

(in thousands)	June 30, 2024	December 31, 2023
EMEP Credit Facility	$48,400	$ 48,400

On November 1, 2021, EMEP entered into a new four-year, senior secured credit facility which provides up to $250 million of commitments. The facility has a maturity date of November 1, 2025. EMEP uses the facility for general corporate purposes. In connection with the credit facility, EMEP incurred financing fees and expenses of approximately $1.4 million as of June 30, 2024 and $1.4 million as of December 31, 2023 before accumulated amortization of $1.0 million as of June 30, 2024 and $0.8 million as of December 31, 2023. 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, occurs semi-annually. Significant declines in commodity prices may result in a decrease in the borrowing base. Our obligations under the credit facility are secured by all of EMEP's crude oil and natural gas properties. We are required to maintain (i) a current ratio greater than 1.0 to 1.0 and (ii) a ratio of total indebtedness-to-EBITDAX of not greater than 3.25 to 1.0, as defined in the Credit Agreement. EMEP was in compliance with all debt covenants as of June 30, 2024.

At our election, interest on borrowings under the credit facility is determined by reference to either (i) a customary benchmark 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 (ii) a customary benchmark 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. 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 borrowing availability.

The borrowing base under the Credit Facility was $75 million as of June 30, 2024.

3. 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 asset retirement obligation activity for the six months ended June 30, 2024:

(in thousands)	**Six Months Ended June 30, 2024**
Asset retirement obligation, January 1	$ 7,150
Accretion of discount expense	232
Asset retirement obligation, June 30	$ 7,382

4. Fair Value

We use commodity-based and financial derivative contracts to manage exposures to commodity price. We do not hold or issue derivative financial instruments for speculative or trading purposes. We periodically enter into futures contracts to hedge our exposure to price fluctuations on crude oil and natural gas sales (Note 5).

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 December 31, 2023 and 2022. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	June 30, 2024		December 31, 2023	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Contingent consideration	$ —	$ —	$ (2,200)	$ (2,200)
Long-term debt	$(48,400)	$(48,400)	$(48,400)	$(48,400)
Net derivative asset (liability)	$ —	$ —	$ 1,005	$ 1,005

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 3).

The fair value of our contingent consideration, net derivative asset (liability) (Note 5) and our long-term debt (Note 3) 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 net derivative asset (liability). As such, an adjustment for counterparty credit risk has been applied to the net derivative asset (liability) to account for the risk of nonperformance by the counterparty.

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			
	June 30, 2024		December 31, 2023	
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Contingent consideration	$ —	$ —	$ (2,200)	$ —
Long-term debt	$ (48,400)	$ —	$ (48,400)	$ —
Net derivative asset (liability)	$ —	$ —	$ 1,005	$ —

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 natural gas properties, asset retirement obligations and other long-lived assets that are written down to fair value when they are impaired.

Commodity Price Hedging Instruments

We periodically enter into futures contracts and costless price collars to hedge our exposure to price fluctuations on crude oil 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. See Note 5.

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

	Asset Derivatives		Liability Derivatives	
(in thousands)	June 30, 2024	December 31, 2023	June 30, 2024	December 31, 2023
Derivatives not designated as hedging instruments:				
Commodity instruments	$ —	$ 2,380	$ —	$ (1,375)
Contingent consideration	$ —	$ —	$ —	$ (2,200)
Total	$ —	$ 2,380	$ —	$ (3,575)

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

	Six Months Ended June 30,	
(in thousands)	2024	2023
Net cash (received from) paid to counterparties	$ 7,423	$ 1,287
Non-cash change in derivative fair value	$ 1,005	$ (7,148)
Derivative fair value (gain) loss	$ 8,428	$ (5,861)

Concentrations of Credit Risk

Our receivables are from a diverse group of companies including major energy companies, pipeline 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 for the other companies.

5. 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 enter futures contracts and costless price collars to hedge our exposure to price fluctuations on crude oil 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. Costless price collars set a ceiling and floor price to hedge exposure to price fluctuations on crude oil and natural gas sales. 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

As of June 30, 2024, we had no outstanding crude oil hedges.

Net settlement losses on oil futures and sell basis swap contracts decreased oil revenues by $7.4 million in the six months ended June 30, 2024 and $1.3 million in the six months ended June 30, 2023. An unrealized loss in the six months ended June 30, 2024 and an unrealized gain in the six months ended June 30, 2023 to record the fair value of derivative contracts decreased oil revenues by $8.4 million in 2024 and increased oil revenues by $5.9 million in 2023.

Natural Gas

As of June 30, 2024, we had no outstanding natural gas hedges.

Net settlement gain on gas futures increased gas revenues by $0.0 million in the six months ended June 30, 2024 and by $0.0 million in the six months ended June 30, 2023. An unrealized gain in the six months ended June 30, 2024 and in the six months ended June 30, 2023 to record the fair value of derivative contracts increased gas revenues by $0.0 million in 2024 and by $0.0 million in 2023.

Contingent Consideration

Pursuant to a contingent consideration arrangement we entered into on August 27, 2021, EMEP is required to pay $2.2 million if the average daily settlement price of NYMEX WTI for calendar year 2022 exceeds $65.00 per barrel and an additional $2.2 million if the average daily settlement price of NYMEX WTI for calendar year 2023 exceeds $60.00 per barrel. In accordance with this contingent agreement, EMEP paid $2.2 million in the six months ended June 30, 2024 and $2.2 million the six months ended June 30, 2022.

6. Commitments and Contingencies

From time to time, the Company 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 Company.

To date, our expenditures to comply with environmental or safety 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.

Commodity Commitments

During 2024 and 2023, we entered into futures contracts that effectively fixed natural gas and crude oil prices for a period of time. See Note 5.

7. Supplemental Cash Flow Information

Interest payments totaled $2.3 million for the six months ended June 30, 2024 and $4.0 million the six months ended June 30, 2023. State income tax payments totaled $0.6 million the six months ended June 30, 2024 and $0.9 million the six months ended June 30, 2023.

8. Subsequent Events

We have evaluated subsequent events through November 13, 2024, the date the financial statements were available to be issued. See Note 1.

Exhibit 99.2

EAGLE MOUNTAIN ENERGY PARTNERS LLC

Consolidated Financials Statements

For the Years Ended December 31, 2023 and 2022

KPMG LLP
Suite 1400
2323 Ross Avenue
Dallas, TX 75201-2721

Independent Auditors' Report

The Members
Eagle Mountain Energy Partners, LLC:

Opinion

We have audited the consolidated financial statements of Eagle Mountain Energy Partners, LLC and its subsidiaries the (Company), which comprise the consolidated balance sheets as of December 31, 2023 and 2022, and the related consolidated statements of income, changes in members' equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Consolidated Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the consolidated financial statements are issued.

Auditors' Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the consolidated financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the consolidated financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

Dallas, Texas
November 13, 2024

Eagle Mountain Energy Partners LLC
Balance Sheets

(in thousands)	December 31, 2023	December 31, 2022
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,594	$ 7,202
Accounts receivable, net	9,015	7,607
Derivative fair value	1,451	—
Other	818	495
Total Current Assets	12,878	15,304
Property and Equipment, at cost – full-cost method:		
Proved properties	183,253	135,088
Other	41	51
Total Property and Equipment	183,294	135,139
Accumulated depreciation, depletion and amortization	(35,503)	(13,316)
Net Property and Equipment	147,791	121,823
Other Assets:		
Derivative fair value	929	—
Other assets	997	1,308
Total Other Assets	1,926	1,308
TOTAL ASSETS	$ 162,595	$ 138,435
LIABILITIES AND MEMBERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 11,374	$ 9,004
Accrued liabilities	6,344	3,723
Derivative fair value	3,575	7,705
Other current liabilities	166	153
Total Current Liabilities	21,459	20,585
Long-term Debt	48,400	38,800
Other Liabilities:		
Asset retirement obligation	7,150	6,299
Derivative fair value	—	4,053
Other liabilities	132	116
Total Other Liabilities	7,282	10,468
Commitments and Contingencies		
Members' Equity:		
Members' equity	85,454	68,582
TOTAL LIABILITIES AND MEMBERS' EQUITY	$ 162,595	$ 138,435

Eagle Mountain Energy Partners LLC
Statements of Income

(in thousands)	Years ended December 31, 2023	2022
REVENUES		
Oil and condensate	$67,804	$ 62,181
Natural gas liquids	3,799	5,025
Natural gas	1,153	2,647
Gain (loss) on derivatives	4,701	(15,345)
Total Revenues	77,457	54,508
EXPENSES		
Production	17,719	16,152
Taxes, transportation and other	6,433	5,916
Depreciation, depletion and amortization	17,906	12,146
Impairment of long-lived assets	4,530	—
Accretion of discount in asset retirement obligation	467	87
General and administrative	(2,016)	(1,152)
Total Expenses	45,039	33,149
OPERATING INCOME	32,418	21,359
OTHER INCOME (EXPENSE)		
Other income	81	19
Loss on contingent consideration	(369)	(1,491)
Interest expense	(4,474)	(2,351)
Total Other Expense	(4,762)	(3,823)
NET INCOME BEFORE INCOME TAX	27,656	17,536
State income taxes	643	868
NET INCOME	$27,013	$ 16,668

Eagle Mountain Energy Partners LLC
Statements of Changes in Members' Equity

(in thousands)	Years ended December 31, 2023	2022
Beginning balance, January 1	$ 68,582	$ 51,793
Net income	27,013	16,668
Member contributions	—	121
Member distributions	(10,141)	—
Ending balance, December 31	$ 85,454	$ 68,582

Eagle Mountain Energy Partners LLC
Statements of Cash Flows

(in thousands)	Years ended December 31, 2023	2022
OPERATING ACTIVITIES		
Net income	$ 27,013	$ 16,668
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	17,906	12,146
Impairment of long-lived assets	4,530	—
Accretion of discount in asset retirement obligation	467	87
Non-cash derivative (gain) loss	(4,332)	16,836
Net cash (paid) received for derivatives	(4,031)	(12,539)
Amortization of deferred financing fees	339	338
Other non-cash items	30	77
Changes in operating assets and liabilities *(a)*	419	5,194
Cash Provided by Operating Activities	42,341	38,807
INVESTING ACTIVITIES		
Proceeds from sale of property and equipment	2,350	3,313
Proved property acquisitions	(19,423)	(26,291)
Development costs	(27,896)	(7,809)
Other property and asset additions	(6)	(8)
Payments on contingent consideration	(2,200)	—
Cash Used in Investing Activities	(47,175)	(30,795)
FINANCING ACTIVITIES		
Proceeds from long-term debt	24,600	21,300
Payments on long-term debt	(15,000)	(23,500)
Member contributions	—	121
Debt issuance costs	—	35
Distributions to members	(10,141)	—
Payments on finance leases	(233)	(262)
Cash Used in Financing Activities	(774)	(2,306)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(5,608)	5,706
Cash and Cash Equivalents, beginning of period	7,202	1,496
Cash and Cash Equivalents, end of period	$ 1,594	$ 7,202
(a) **Changes in Operating Assets and Liabilities**		
Accounts receivable	$ (1,408)	$ 274
Other current assets	(323)	(297)
Current liabilities	2,150	5,217
	$ 419	$ 5,194

1. Organization and Summary of Significant Accounting Policies

The accompanying audited financial statements represent Eagle Mountain Energy Partners' ("EMEP") approximately 88% share of the EMEP Properties (as defined below). EMEP is a Delaware limited liability company ("LLC") formed on January 10, 2020, and is engaged in the exploration, development, production and sale of crude oil and natural gas primarily in Montana and North Dakota ("Williston Basin Properties"). Its executive offices are located in Houston, Texas.

As an LLC, the amount of loss at risk for each individual member is limited to the amount of capital contributed to the LLC and, unless otherwise noted, the individual member's liability for indebtedness of an LLC is limited to the member's actual capital contribution.

On August 30, 2024, MorningStar Operating LLC completed the acquisition from a wholly-owned subsidiary of EMEP andV4-ELM, LP, a Texas limited partnership ("Vendera" and together with EMEP, the "EMEP Entities") of producing properties in the Greater Williston Basin of Montana and North Dakota (the "EMEP Properties") for approximately $241.8 million and 2.5 million common units valued at $50.0 million. The purchase price was allocated primarily to proved properties.

The accompanying consolidated financial statements include the financial statements of EMEP and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

Basis of Presentation

The accounts of EMEP are presented in the accompanying financial statements. These financial statements have been prepared in accordance with U.S. GAAP.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. Significant items subject to such estimates and assumptions include the following:

- estimates of proved reserves and related estimates of the present value of future revenues;
- the recoverability of oil and gas properties;
- contingent consideration arrangements;
- estimates of revenue earned but not yet received;
- asset retirement obligations; and
- legal and environmental risks and exposure.

Cash and Cash Equivalents

Cash equivalents are considered to be all highly liquid investments having an original maturity of three months or less.

Concentrations of Credit Risk

Financial instruments that potentially subject EMEP to a concentration of credit risk consist principally of cash, accounts receivable, and derivative financial instruments.

Our receivables are from a diverse group of companies including major energy companies, pipeline 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. Including the bank that issued the letter of credit, we currently have greater concentrations of credit with several investment-grade (BBB- or better) rated companies.

Our production is sold to various purchasers, based on their credit rating and the location of our production. Sales to four purchasers for the year ended December 31, 2023 and four purchasers for the year ended December 31, 2022, were greater than 10% of total revenues. We believe that alternative purchasers are available, if necessary, to purchase production at prices substantially similar to those received from these significant purchasers.

Customer	2023	2022
Customer A	41%	48%
Customer B	17%	22%
Customer C	16%	12%
Customer D	15%	10%

Property and Equipment

EMEP follows the full-cost method of accounting for its oil and natural gas properties. Accordingly, all productive and nonproductive costs directly associated with the acquisition, exploration and development of oil and natural gas properties, including the cost of undeveloped leaseholds, dry holes and leasehold equipment, are capitalized to cost centers for the United States. All costs related to production, general corporate overhead and similar activities are expensed as incurred.

Depreciation, depletion, and amortization (DD&A) of capitalized costs within a cost center are depleted on a compositeunit-of-production method based on estimated proved oil and gas reserves. The composite unit-of-production depletion rate is calculated by dividing current period production by estimated proved oil and gas reserves at the beginning of the period then applying such depletion rate to proved property costs, which include estimated asset retirement costs, less accumulated depletion, plus the estimated future expenditures to be incurred in developing proved reserves, net of estimated salvage values. At December 31, 2023 and 2022, all of EMEP’s oil and natural gas revenues come from wells with proven reserve estimates that were prepared by an independent engineering firm.

At the end of each fiscal year, the net oil and gas properties, less related deferred income taxes, are limited to the “cost center ceiling” equal to (i) the sum of (a) the present value of estimated future net revenues from proved oil and natural gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (b) the costs of unproved properties not being amortized, and (c) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects. Any excess of the net book value of oil and natural gas properties, less related deferred income taxes, over the cost center ceiling is recognized as an impairment of proved oil and natural gas properties.

The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of crude oil, NGLs and natural gas on the first calendar date of each month during the 12-month period prior to the end of the current fiscal year, held flat for the life of the production. Prices do not include the impact of commodity derivative contracts.

During the year end ended December 31, 2023, EMEP recognized an impairment of long-lived assets of $4.5 million primarily due to a significant increase in future development costs included in the depletable base of proved reserves as well as a decrease in crude oil prices. During the year ended December 31, 2022, EMEP did not recognize an impairment of long-lived assets.

Proceeds from the sale of oil and natural gas properties are accounted for as a reduction of capitalized costs unless such sales involve a significant change between costs and the fair value of proved reserves, in which a gain or loss is recognized. For the years ended December 31, 2023 and 2022, EMEP did not have any such sales of oil and natural gas properties.

Asset Retirement Obligation

If the fair value for asset retirement obligation can be reasonably estimated, the liability is recognized in the period when it is incurred. Oil and gas producing companies incur this liability upon acquiring or drilling a well. The retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with an offsetting increase to proved properties on the balance sheet. Periodic accretion of discount of the estimated liability is recorded as an expense in the statements of operations. See Note 4.

Derivatives

EMEP uses derivatives to hedge against changes in cash flows related to product price, as opposed to their use for trading purposes. EMEP records all derivatives on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. See Note 6.

EMEP has entered into agreements for acquisitions of oil and natural gas properties that include obligations to pay the seller additional consideration if commodity prices exceed specified thresholds during certain periods in the future. These contingent consideration liabilities are required to be bifurcated and accounted for separate as derivative instruments and recognized at their acquisition date fair value in the consolidated balance sheets.

EMEP does not designate these derivative contracts as cash flow hedges. Changes in the fair value of commodity price derivatives, including contingent consideration agreements, are recognized currently in earnings. Realized and unrealized gains and losses on commodity price derivatives are recognized in gain (loss) on derivatives, and on contingent consideration agreements in loss on contingent consideration. Deferred premium obligations associated with commodity price derivatives are recognized as gain (loss) on derivatives. Settlements of derivatives are included in cash flows from operating activities and settlements on contingent consideration agreements are included in cash flows from financing activites up to the acquisition date fair value with any excess classified as cash flows used in investing activities.

Revenue Recognition

Oil, gas and natural gas liquids revenues are recognized upon the satisfaction of the performance obligation which occurs at the point in time when control of the product transfers to a customer, in an amount that reflects the consideration to which the Partnership expects to be entitled in exchange for the product.

The transaction price used to recognize revenue is a function of the contract billing terms which are indexed to a market price or an average index price. Performance obligations are considered satisfied upon transfer of control of the commodity. Revenue is recognized in the amount expected to be received once the consideration is adequately estimated (i.e., when market prices are known). Contracts with customers typically require payment within 30 days following invoicing.

The majority of the Company's sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC 606-10-50-14 exempting the Company 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.

Fair Value of Financial Instruments

Fair value is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

Assets and liabilities recorded at fair value in the consolidated balance sheets are categorized based upon the level of judgment associated with the inputs used to measure their fair value. Hierarchical levels directly related to the amount of subjectivity associated with the inputs to fair valuation of these assets and liabilities are as follows:

Level I—Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities at the measurement date.

Level II—Inputs (other than quoted prices included in Level I) are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.

Level III—Inputs reflect management's best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

Income Taxes

EMEP is organized as an LLC and taxed as a partnership for federal income tax purposes with income tax liabilities and/or benefits of the Partnership passed through to the partners. As such, we are not a taxable entity, we do not directly pay federal income tax and recognition has not been given to federal income taxes for our operations.

State income positions are evaluated in a two-step process. EMEP first determines whether it is more likely than not that a tax position will be sustained upon examination. If a tax position meets the more likely than not threshold, it is then measured to determine the amount of expense to record in the consolidated financial statements. The tax expense recorded would equal the largest amount of expense related to the outcome that is 50% or greater likely to occur.

Limited partnerships are subject to state income taxes in certain states. Income taxes related to state taxes have been included as a separate line in the statements of operations and no deferred tax amounts were calculated.

Loss Contingencies

When management determines that it is probable that an asset has been impaired or a liability has been incurred, we accrue our best estimate of the loss if it can be reasonably estimated. Any legal costs related to litigation are expensed as incurred.

Liquidity

Our primary sources of liquidity are cash provided by operating activities, borrowings under our credit facility and equity raised from members. Short-term liquidity needs are provided by borrowings under our credit facility. We believe that we have a sufficient combination of resources and operating flexibility to ensure that we remain in compliance with our future debt covenants for all of our outstanding debt for at least the next 12 months from the date of issuance of these financial statements. See Note 3.

Leases

Under ASC 842, EMEP recognized a right-of-use ("ROU") asset and lease liability to account for its leases. ROU assets represent EMEP's right to use an underlying asset for the lease term and lease liabilities represent EMEP's obligation to make lease payments arising from the lease. ROU assets and lease liabilities are recognized on the commencement date based on the present value of lease payments over the lease term. ROU assets are based on the lease liability and are increased by prepaid lease payments and decreased by lease incentives received. Lease incentives are amortized through the lease asset as reductions of expense over the lease term. For leases where EMEP is reasonably certain to exercise a renewal option, such option periods have been included in the determination of EMEP's ROU assets and lease liabilities.

2. Acquisitions

On March 1, 2023, EMEP completed the acquisition of producing properties in the Williston Basin in Montana from Grayson Mill Williston, LLC and Glacier Peak Midstream, LLC (collectively, "Grayson") for approximately $19.4 million. The purchase price allocation included $19.9 million to proved properties, $0.1 million to other current liabilities and $0.4 million to asset retirement obligation. The acquisition was funded by cash on hand and borrowings from our credit facility.

On August 1, 2022, EMEP completed the acquisition of producing properties in the Williston Basin in Montana and North Dakota from Ovintiv USA Inc. ("Ovintiv") for approximately $27.2 million. The purchase price allocation included $28.2 million to proved properties, $0.8 million as other current assets, $1.0 million to other current liabilities and $0.8 million to asset retirement obligation. The acquisition was funded by cash on hand and borrowings from our credit facility.

Concurrent with closing the Grayson acquisition on March 1, 2023, EMEP sold a portion of the mineral interest acquired to an unrelated party for approximately $2.4 million. The assets sold were allocated based on the relative fair value of the total purchase price, therefore no gain or loss was incurred on this transaction.

Concurrent with closing the Ovintiv acquisition on August 1, 2022, EMEP sold a portion of the mineral interest acquired to an unrelated party for approximately $3.3 million. The assets sold were allocated based on the relative fair value of the total purchase price, therefore no gain or loss was incurred on this transaction.

3. Debt

(in thousands)	**December 31, 2023**	**December 31, 2022**
EMEP Credit Facility	$ 48,400	$ 38,800

On November 1, 2021, EMEP entered into a new four-year, senior secured credit facility which provides up to $250 million of commitments. The facility has a maturity date of November 1, 2025. We use the facility for general corporate purposes. In connection with the credit facility, we incurred financing fees and expenses of approximately $1.4 million as of December 31, 2023 and $1.4 million as of December 31, 2022 before accumulated amortization of $0.8 million as of December 31, 2023 and $0.5 million as of December 31, 2022. 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, occurs semi-annually. Significant declines in commodity prices may result in a decrease in the borrowing base. Our obligations under the credit facility are secured by all of EMEP's crude oil and natural gas properties. We are required to maintain (i) a current ratio greater than 1.0 to 1.0 and (ii) a ratio of total indebtedness-to-EBITDAX of not greater than 3.25 to 1.0, as defined in the Credit Agreement. EMEP was in compliance with all debt covenants as of December 31, 2023.

At our election, interest on borrowings under the credit facility is determined by reference to either (i) a customary benchmark 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 (ii) a customary benchmark 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. 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 borrowing availability. The weighted average interest rate on credit facility borrowings was 9.0% in 2023 and 8.1% in 2022.

The borrowing base under the Credit Facility was $75 million as of December 31, 2023, and was $65 million as of December 31, 2022.

4. 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 asset retirement obligation activity for the years ended December 31, 2023 and 2022:

	Year Ended December 31,	
(in thousands)	2023	2022
Asset retirement obligation, January 1	$ 6,299	$ 5,445
Liability incurred upon acquiring and drilling wells	384	767
Accretion of discount expense	467	87
Asset retirement obligation, December 31	$ 7,150	$ 6,299

5. Fair Value

We use commodity-based and financial derivative contracts to manage exposures to commodity price. We do not hold or issue derivative financial instruments for speculative or trading purposes. We periodically enter into futures contracts to hedge our exposure to price fluctuations on crude oil and natural gas sales (Note 6).

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 December 31, 2023 and 2022. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	December 31, 2023		December 31, 2022	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Contingent consideration	$ (2,200)	$ (2,200)	$ (4,030)	$ (4,030)
Long-term debt	$(48,400)	$(48,400)	$(38,800)	$(38,800)
Net derivative asset (liability)	$ 1,005	$ 1,005	$ (7,728)	$ (7,728)

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 3).

The fair value of our contingent consideration, net derivative asset (liability) (Note 6) and our long-term debt (Note 3) 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 net derivative asset (liability). As such, an adjustment for counterparty credit risk has been applied to the net derivative asset (liability) to account for the risk of nonperformance by the counterparty.

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			
	December 31, 2023		December 31, 2022	
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Contingent consideration	$ (2,200)	$ —	$ (4,030)	$ —
Long-term debt	$ (48,400)	$ —	$ (38,800)	$ —
Net derivative asset (liability)	$ 1,005	$ —	$ (7,728)	$ —

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 natural gas properties, asset retirement obligations and other long-lived assets that are written down to fair value when they are impaired.

Commodity Price Hedging Instruments

We periodically enter into futures contracts and costless price collars to hedge our exposure to price fluctuations on crude oil 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. See Note 6.

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

(in thousands)	Asset Derivatives December 31, 2023	Asset Derivatives December 31, 2022	Liability Derivatives December 31, 2023	Liability Derivatives December 31, 2022
Derivatives not designated as hedging instruments:				
Commodity instruments	$ 2,380	$ —	$(1,375)	$ (7,728)
Contingent consideration	$ —	$ —	$(2,200)	$ (4,030)
Total	$ 2,380	$ —	$(3,575)	$(11,758)

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

(in thousands)	2023	2022
Net cash (received from) paid to counterparties	$ 4,031	$12,539
Non-cash change in derivative fair value	$(8,363)	$ 4,297
Derivative fair value (gain) loss	$(4,332)	$16,836

6. 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 enter futures contracts and costless price collars to hedge our exposure to price fluctuations on crude oil 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. Costless price collars set a ceiling and floor price to hedge exposure to price fluctuations on crude oil and natural gas sales. 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. See Note 5.

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl
January 2024 – March 2024	1,800	$ 71.26
April 2024 – June 2024	1,710	$ 72.07
July 2024 – September 2024	1,441	$ 70.31
October 2024 – December 2024	1,038	$ 72.27
January 2025 – December 2025	657	$ 72.62

Net settlement losses on oil futures and sell basis swap contracts decreased oil revenues by $4.2 million in 2023 and $11.0 million in 2022. An unrealized gain in 2023 and an unrealized loss in 2022 to record the fair value of derivative contracts increased oil revenues by $3.7 million in 2023 and decreased oil revenues by $13.3 million in 2022.

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 5.

Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu
January 2024 – March 2024	521	$ 3.42
April 2024 – June 2024	769	$ 2.87
July 2024 – September 2024	748	$ 2.95
October 2024 – December 2024	491	$ 3.04

Net settlement gain on gas futures increased gas revenues by $0.2 million in 2023 and losses decreased gas revenues by $1.5 million in 2022. An unrealized gain in 2023 and an unrealized loss in 2022 to record the fair value of derivative contracts increased gas revenues by $1.0 million in 2023 and decreased gas revenues by $2.1 million in 2022.

Contingent Consideration

Pursuant to a contingent consideration arrangement we entered into on August 27, 2021, EMEP is required to pay $2.2 million if the average daily settlement price of NYMEX WTI for calendar year 2022 exceeds $65.00 per barrel and an additional $2.2 million if the average daily settlement price of NYMEX WTI for calendar year 2023 exceeds $60.00 per barrel. In accordance with this contingent agreement, EMEP paid $2.2 million in the first quarter of 2023 and has recorded a contingent liability of $2.2 million as of December 31, 2023. Payment of this contingent liability was made in the first quarter of 2024.

7. Members' Equity and Incentive Units

Profits and losses will be determined and allocated with respect to each fiscal year as of the end of such fiscal year. Profits and losses will be allocated among the members in a manner such that the adjusted capital account of each member is as nearly as possible, equal (proportionately) to the distributions that would be made to such member if EMEP were dissolved. The members of EMEP have committed to contribute $90.9 million of which $57.5 million was contributed as of December 31, 2023.

The LLC agreement authorizes EMEP to issue incentive units. As of December 31, 2023, 3,000,000 incentive units were authorized, and 2,205,000 units were issued and outstanding. The incentive units are designed as a profits interest, and the incentive unit holders are entitled to an increased share of the distributable cash flow generated by EMEP in the event that certain performance hurdles are met. Given the metrics set forth by the incentive unit plan and the limited history of EMEP as well as the practical scenarios under which similar instruments are typically realized (units typically do not have a value until a major asset liquidation occurs, which cannot be deemed "probable" under GAAP until it has occurred), the realization of these units is not probable at the date of grant. Due to the nature of the incentive units, no compensation expense was recorded during the years ended December 31, 2023 and 2022.

8. Commitments and Contingencies

From time to time, the Company 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 Company.

To date, our expenditures to comply with environmental or safety 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.

Commodity Commitments

During 2023 and 2022, we entered into futures contracts that effectively fixed natural gas and crude oil prices. See Note 6.

9. Supplemental Cash Flow Information

Interest payments totaled $4.0 million for in 2023 and $1.7 million in 2022. State income tax payments totaled $0.9 million in 2023 and $0.0 million in 2022.

10. Subsequent Events

We have evaluated subsequent events through November 13, 2024, the date the financial statements were available to be issued.

On February 8, 2024, EMEP's borrowing base was reaffirmed and remained at $75 million.

In February 2024, EMEP entered into new commodity derivative contracts, including NYMEX WTI price swaps and costless price collars.

Exhibit 99.3

VENDERA PROPERTIES

Statements of Revenues and Direct Operating Expenses

For the Six Months Ended June 30, 2024 and 2023

TXO Partners, LP
Vendera Statement of Revenues and Direct Operating
Expenses of the Vendera Properties (as described in Note 1)

(in thousands)	Six months ended June 30, 2024	Six months ended June 30, 2023
REVENUES		
Oil and condensate	$4,679	$3,965
Natural gas liquids	249	255
Natural gas	18	94
Total Revenues	4,946	4,314
DIRECT OPERATING EXPENSES		
Production	1,208	1,118
Taxes, transportation and other	399	414
Total Direct Operating Expenses	1,607	1,532
Revenues in Excess of Direct Operating Expenses	$3,339	$2,782

Notes to the Statements of Revenues and Direct Operating Expenses of the Vendera Properties

(1) Basis of Presentation

On August 30, 2024, TXO Partners, LP ("TXO"), through its wholly-owned subsidiary, MorningStar Operating LLC, completed the acquisition from EMEP Acquisitions, LLC, a Texas limited liability company ("EMEP") and VR4-Elm, LP, a Texas limited partnership ("Vendera" and, together with EMEP, the "EMEP Entities") of producing properties in the Greater Williston Basin of Montana and North Dakota ("Williston Basin Properties") for approximately $241.8 million and 2.5 million common units, valued at $50.0 million. The purchase price was allocated primarily to proved properties.

The accompanying unaudited statement includes revenues from oil, natural gas liquids and natural gas production and direct operating expenses associated with the Williston Basin Properties and were derived from the EMEP Entities historical accounting records and represent Vendera's 12% ownership interest in the underlying Williston Basin Properties. The accompanying statement varies from a complete income statement in accordance with US GAAP in that they do not reflect certain indirect expenses that were incurred in connection with the ownership and operation of the Williston Basin Properties including, but not limited to, general and administrative expenses, interest expense and income tax expense. These costs were not separately allocated to the Williston Basin Properties in the accounting records of Vendera. In addition, these allocations, if made using historical general and administrative structures and tax burdens, would not produce allocations that would be indicative of the historical performance of the Williston Basin Properties had it been a TXO property due to the differing size, structure, operations and accounting policies of the EMEP Entities and TXO. The accompanying statement also does not include provisions for depreciation, depletion, amortization and accretion, as such amounts would not be indicative of the costs that TXO will incur upon the allocation of the purchase price paid for the Williston Basin Properties. Furthermore, no balance sheet has been presented for the Williston Basin Properties because the acquired properties were not accounted for as a separate subsidiary or division of Vendera and complete financial statements are not available, nor has information about the Williston Basin Properties' operating, investing and financing cash flows been provided for similar reasons. Accordingly, the historical Statement of Revenues and Direct Operating Expenses of the Vendera Properties is presented in lieu of the full financial statements required under Item 3-05 of Securities and Exchange Commission ("SEC") Regulation S-X.

This Statement of Revenues and Direct Operating Expenses is not indicative of the results of operations for the Williston Basin Properties on a go forward basis.

(2) Summary of Significant Accounting Policies

Use of Estimates—The Statement of Revenues and Direct Operating Expenses is derived from the historical operating statements of the EMEP Entities. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the reported amounts of revenues and direct operating expenses during the respective reporting periods. Actual results could be different from those estimates.

Revenue Recognition—Total revenues in the accompanying statements include the sale of crude oil, natural gas liquids and natural gas, net of royalties. The EMEP Entities recognize revenues upon the satisfaction of the applicable performance obligation, which occurs at the point in time when control of the product transfers to a customer, in an amount that reflects the consideration to which the EMEP Entities expects to be entitled in exchange for such product.

During the six month periods ended June 30, 2024 and 2023, four customers accounted for more than 10% of the total revenues of the Williston Basin Properties.

Direct Operating Expenses—Direct operating expenses are recognized when incurred and consist of direct expenses of operating the Williston Basin Properties. The direct operating expenses include lease operating, production taxes, processing and transportation expenses. Lease operating expenses include lifting costs, well repair expenses, facility maintenance expenses, well workover costs, and other field related expenses. Lease operating expenses also include expenses directly associated with support personnel, support services, equipment, and facilities directly related to oil and gas production activities.

(3) Contingencies

The activities of the Williston Basin Properties may become subject to potential claims and litigation in the normal course of operations. TXO does not believe that any liability resulting from any pending or threatened litigation will have a material adverse effect on the operations or financial results of the Williston Basin Properties.

(4) Subsequent Events

TXO has evaluated events through November 13, 2024, the date the Statements of Revenues and Direct Operating Expenses were available to be issued, and are not aware of any events that have occurred that require adjustments to or disclosure in the financial statements.

Exhibit 99.4

VENDERA PROPERTIES

Statements of Revenues and Direct Operating Expenses

Years Ended December 31, 2023 and 2022

Independent Auditors' Report

To the Partners
TXO Energy Partners, L.P.:

Report on the Audit of the Statements of Revenues and Direct Operating Expenses

Opinion

We have audited the accompanying statements of revenues and direct operating expenses (the Statements) of certain oil and gas properties acquired from VR4-Elm, L.P. (the Properties) by TXO Energy Partners, L.P. (the Partnership) for the years ended December 31, 2023 and 2022, and the related notes to the statements.

In our opinion, the Statements present fairly, in all material respects, the revenues and direct operating expenses of the Properties for the years ended December 31, 2023 and 2022 in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audits of the Statements section of our report. We are required to be independent of the Partnership and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Other Matter

U.S. generally accepted accounting principles require that the Supplementary Oil and Gas Disclosures contained herein be presented to supplement the basic Statements. Such information, although not a part of the basic Statements, is required by the Financial Accounting Standards Board who considers it to be an essential part of the financial reporting for placing the basic Statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic Statements, and other knowledge we obtained during our audit of the basic Statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Responsibilities of Management for the Statements

Management is responsible for the preparation and fair presentation of the Statements in accordance with U.S. generally accepted accounting principles, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of Statements that are free from material misstatement, whether due to fraud or error.

In preparing the Statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Property's ability to continue as a going concern for one year after the date that the Statements are issued.

Auditors' Responsibilities for the Audit of the Statements

Our objectives are to obtain reasonable assurance about whether the Statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the Statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the Statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the Statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the internal control related to the Properties. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the Statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Properties' ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

Dallas, Texas
November 13, 2024

TXO Partners, LP
Vendera Statement of Revenues and Direct Operating Expenses of the Vendera Properties (as described in Note 1)

(in thousands)	Years ended December 31, 2023	2022
REVENUES		
Oil and condensate	$9,124	$8,367
Natural gas liquids	511	676
Natural gas	155	356
Total Revenues	9,790	9,399
DIRECT OPERATING EXPENSES		
Production	2,384	2,173
Taxes, transportation and other	866	796
Total Direct Operating Expenses	3,250	2,969
Revenues in Excess of Direct Operating Expenses	$6,540	$6,430

See accompanying notes to Statements of Revenues and Direct Operating Statements.

Notes to the Statements of Revenues and Direct Operating Expenses of the Vendera Properties

(1) Basis of Presentation

On August 30, 2024, TXO Partners, LP ("TXO"), through its wholly-owned subsidiary, MorningStar Operating LLC, completed the acquisition from EMEP Acquisitions, LLC, a Texas limited liability company ("EMEP") and VR4-Elm, LP, a Texas limited partnership ("Vendera" and, together with EMEP, the "EMEP Entities") of producing properties in the Greater Williston Basin of Montana and North Dakota ("Williston Basin Properties") for approximately $241.8 million and 2.5 million common units, valued at $50.0 million. The purchase price was allocated primarily to proved properties.

The accompanying audited statement includes revenues from oil, natural gas liquids and natural gas production and direct operating expenses associated with the Williston Basin Properties and were derived from the EMEP Entities historical accounting records and represent Vendera's 12% ownership interest in the underlying Williston Basin Properties. The accompanying statement varies from a complete income statement in accordance with US GAAP in that they do not reflect certain indirect expenses that were incurred in connection with the ownership and operation of the Williston Basin Properties including, but not limited to, general and administrative expenses, interest expense and income tax expense. These costs were not separately allocated to the Williston Basin Properties in the accounting records of Vendera. In addition, these allocations, if made using historical general and administrative structures and tax burdens, would not produce allocations that would be indicative of the historical performance of the Williston Basin Properties had it been a TXO property due to the differing size, structure, operations and accounting policies of the EMEP Entities and TXO. The accompanying statement also does not include provisions for depreciation, depletion, amortization and accretion, as such amounts would not be indicative of the costs that TXO will incur upon the allocation of the purchase price paid for the Williston Basin Properties. Furthermore, no balance sheet has been presented for the Williston Basin Properties because the acquired properties were not accounted for as a separate subsidiary or division of Vendera and complete financial statements are not available, nor has information about the Williston Basin Properties' operating, investing and financing cash flows been provided for similar reasons. Accordingly, the historical Statement of Revenues and Direct Operating Expenses of the Vendera Properties is presented in lieu of the full financial statements required under Item 3-05 of Securities and Exchange Commission ("SEC") Regulation S-X.

This Statement of Revenues and Direct Operating Expenses is not indicative of the results of operations for the Williston Basin Properties on a go forward basis.

(2) Summary of Significant Accounting Policies

Use of Estimates—The Statement of Revenues and Direct Operating Expenses is derived from the historical operating statements of the EMEP Entities. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the reported amounts of revenues and direct operating expenses during the respective reporting periods. Actual results could be different from those estimates.

Revenue Recognition—Total revenues in the accompanying statements include the sale of crude oil, natural gas liquids and natural gas, net of royalties. The EMEP Entities recognize revenues upon the satisfaction of the applicable performance obligation, which occurs at the point in time when control of the product transfers to a customer, in an amount that reflects the consideration to which the EMEP Entities expects to be entitled in exchange for such product.

For the years ended December 31, 2023 and 2022, four customers accounted for more than 10% of the total revenues of the Williston Basin Properties.

Direct Operating Expenses—Direct operating expenses are recognized when incurred and consist of direct expenses of operating the Williston Basin Properties. The direct operating expenses include lease operating, production taxes, processing and transportation expenses. Lease operating expenses include lifting costs, well repair expenses, facility maintenance expenses, well workover costs, and other field related expenses. Lease operating expenses also include expenses directly associated with support personnel, support services, equipment, and facilities directly related to oil and gas production activities.

(3) Contingencies

The activities of the Williston Basin Properties may become subject to potential claims and litigation in the normal course of operations. TXO does not believe that any liability resulting from any pending or threatened litigation will have a material adverse effect on the operations or financial results of the Williston Basin Properties.

(4) Subsequent Events

TXO has evaluated events through November 13, 2024, the date the Statements of Revenues and Direct Operating Expenses were available to be issued, and are not aware of any events that have occurred that require adjustments to or disclosure in the financial statements.

Supplementary Oil and Gas Disclosures (Unaudited)

Supplemental reserve information

The following unaudited supplemental reserve information summarizes the net proved reserves of oil, natural gas liquids and natural gas and the standardized measure thereof attributable to the Williston Basin Properties as of December 31, 2023 and December 31, 2022. All of the reserves are located in the United States. The reserve disclosures are based on reserve studies prepared in accordance with the guidelines established by the SEC.

There are numerous uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and the amount and timing of development expenditures, including many factors beyond the property owner's control. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil, natural gas liquids and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because all reserve estimates are to some degree subjective, the quantities of oil, natural gas liquids and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil, natural gas liquids and natural gas sales prices may each differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. The standardized measure shown below represents estimates only and should not be construed as the current market value of the estimated oil, natural gas liquids and natural gas reserves attributable to the Vendera Properties. In this regard, the information set forth in the following tables includes revisions of reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent development activities, production history of the Williston Basin Properties and any adjustments in the projected economic life of such property resulting from changes in product prices.

Estimated quantities of oil, NGL and gas reserves

The following table sets forth certain data pertaining to the Williston Basin Properties proved developed reserves as of December 31, 2023, December 31, 2022 and December 31, 2021 and for the period from December 31, 2021 to December 31, 2023.

	Oil (MBbl)	NGL (MBbl)	Gas (MMCF)	Total (MBoe)
December 31, 2021	1,189	250	1,373	1,668
Revision of previous estimates	166	38	198	237
Production	(80)	(16)	(94)	(112)
December 31, 2022	1,275	272	1,477	1,793
Revision of previous estimates	21	(3)	(44)	11
Production	(101)	(20)	(107)	(139)
Ending balance, December 31, 2023	1,195	249	1,326	1,665
Proved Developed Reserves				
December 31, 2021	1,189	250	1,373	1,668
December 31, 2022	1,275	272	1,477	1,793
December 31, 2023	1,195	249	1,326	1,665

Standardized Measure of Discounted Future Net Cash Flows

The Standardized Measure of Discounted Future Net Cash Flows (excluding income tax expense) relating to proved crude oil, natural gas liquids and natural gas reserves is presented below:

	December 31, 2022	December 31, 2023
Future cash inflows	$ 131,777	$ 98,396
Future development and abandonment costs(a)	(7,906)	(7,906)
Future production expense	(49,048)	(41,437)
Future net cash flows	74,823	49,053
Discounted at 10% per year	(31,373)	(17,481)
Standardized measure of discounted future net cash flows	$ 43,450	$ 31,572

(a) Future development and abandonment costs include $7.9 million as of December 31, 2023 and December 31, 2022, of undiscounted future asset retirement expenditures estimated as of those dates using current estimates of future abandonment costs.

Notes to the Statements of Revenues and Direct Operating Expenses of the Vendera Properties

The Standardized Measure of Discounted Future Net Cash Flows (discounted at 10%) from production of proved reserves was developed as follows:

- An estimate was made of the quantity of proved reserves and the future periods in which they are expected to be produced based on current economic conditions.
- In accordance with SEC guidelines, the engineers' estimates of future net revenues from proved properties and the present value thereof are made using the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. These prices are held constant throughout the life of the properties, except where such guidelines permit alternate treatment. Average realized oil prices used in the estimation of proved reserves and calculation of the standardized measure were $76.09 for 2023, $91.10 for 2022 and $64.73 for 2021. Average realized natural gas liquids prices were $32.10 for 2023, $38.98 for 2022 and $27.85 for 2021. Average realized gas prices were -$0.39 for 2023, $3.41 for 2022 and $0.68 for 2021.
- The future gross revenue streams were reduced by estimated future operating costs and future development and abandonment costs, all of which were based on current costs in effect at the date presented and held constant throughout the life of the properties.

As described in Note 1, these Statements of Revenue and Direct Operating Expenses do not include income tax expense or balance sheet information; therefore, income tax and capital expenditure estimates were omitted from the Standardized Measure of Discounted Future Net Cash Flows calculation. The principal sources of changes in the Standardized Measure of Discounted Future Net Cash Flows for each of the periods presented below are as follows:

	Years ended	
	December 31, 2022	December 31, 2023
Balance, beginning of year	$ 25,947	$ 43,450
Oil and gas sales, net of production costs	(6,440)	(6,550)
Net change in sales prices and production costs	31,290	(2,597)
Changes in production rates (timing) and other	6,134	(4,902)
Revision of quantity estimates	(16,076)	(2,174)
Accretion of discount	2,595	4,345
Standardized measure of discounted future net cash flows	$ 43,450	$ 31,572

TXO PARTNERS, L.P.

PRO FORMA FINANCIAL STATEMENTS

(Unaudited)

Introduction

TXO Partners, L.P. (“TXO Partners”) engages in oil and natural gas exploration and production. The unaudited pro forma financial statements have been prepared in accordance with Article 11 of Regulation S-X, using assumptions set forth in the notes to the unaudited pro forma financial statements. The following unaudited pro forma financial statements of TXO Partners reflect the historical results of TXO Partners, on a pro forma basis to give effect to the following transactions, which are described in further detail below, as if they had occurred on June 30, 2024, for pro forma balance sheet purposes, and on January 1, 2023, for pro forma statement of operations purposes:

- in the case of the unaudited pro forma statements of operations, the acquisition of producing properties in the Williston Basin of Montana and North Dakota from Eagle Mountain Energy Partners and Vendera V4-ELM, LP, (collectively, the “EMEP Entities”) (“EMEP Acquisition”) in August 2024, including the 2.5 million units issued as part of the consideration paid; and
- an underwritten public offering of 6.5 million common units on June 28, 2024 at a price of $20.00 per common unit resulting in proceeds of $122.5 million net of underwriting discounts, commissions and other costs (“the Offering”) and the underwritten public offering of an additional 975,000 common units at a price of $20.00 per common unit pursuant to the underwriter’s exercise in full of its option to purchase additional common units in the Offering on July 2, 2024, resulting in additional proceeds of $18.7 million net of underwriting discounts, commissions and other costs. We used the net proceeds from the Offering to fund a portion of the cash consideration for the EMEP Acquisition.

The unaudited pro forma balance sheet of TXO Partners is based on the historical balance sheet of TXO Partners as of June 30, 2024 and includes pro forma adjustments to give effect to the described transactions as if they had occurred on June 30, 2024. The unaudited pro forma statements of operations of the TXO Partners are based on the audited historical statement of operations of TXO Partners for the year ended December 31, 2023, and the unaudited historical statement of operations of TXO Partners for the six months ended June 30, 2024, both having been adjusted to give effect to the described transactions as if they occurred on January 1, 2023.

The pro forma data presented reflect events directly attributable to the described transactions and certain assumptions TXO Partners believes are reasonable. The pro forma data are not necessarily indicative of financial results that would have been attained had the described transactions occurred on the date indicated or which could be achieved in the future because they necessarily exclude various operating expenses, such as incremental general and administrative expenses associated with being a larger company. The adjustments are based on currently available information and certain estimates and assumptions. Therefore, the actual adjustments may differ from the pro forma adjustments. However, management believes that the assumptions provide a reasonable basis for presenting the significant effects of the transactions and the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the unaudited financial statements.

The unaudited pro forma financial statements and related notes are presented for illustrative purposes only. If the EMEP Acquisition and Offering described herein had occurred in the past, TXO Partners’ operating results might have been materially different from those presented in the unaudited pro forma financial statements. The unaudited pro forma financial statements should not be relied upon as an indication of operating results that TXO Partners would have achieved if the EMEP Acquisition and Offering described herein had taken place on the specified date. In addition, future results may vary significantly from the results reflected in the unaudited pro forma financial statements of operations and should not be relied upon as an indication of the future results TXO Partners will have after the EMEP Acquisition and Offering described herein by these unaudited pro forma financial statements.

TXO PARTNERS, L.P.
PRO FORMA BALANCE SHEET
June 30, 2024

(in thousands)	TXO, Partners Historical	Offering	EMEP Acquisition	Pro Forma
ASSETS				
Current Assets:				
Cash and cash equivalents	$ 75,999(a)	$ 18,745(a)	$ (66,160)	$ 28,584
Accounts receivable, net	28,509	—	—	28,509
Other	12,515	—	278	12,793
Total Current Assets	117,023	18,745	(65,882)	69,886
Property and Equipment, at cost – successful efforts method:				
Proved properties	1,578,274	—	284,551	1,862,825
Unproved properties	18,648	—	—	18,648
Other	84,574	—	569	85,143
Total Property and Equipment	1,681,496	—	285,120	1,966,616
Accumulated depreciation, depletion and amortization	(1,033,940)	—	—	(1,033,940)
Net Property and Equipment	647,556	—	285,120	932,676
Other Assets:				
Note receivable from related party	7,131	—	—	7,131
Other	2,809	—	967	3,776
Total Other Assets	9,940	—	967	10,907
TOTAL ASSETS	$ 774,519	$ 18,745	$ 220,205	1,013,469
LIABILITIES AND PARTNERS' CAPITAL				
Current Liabilities:				
Accounts payable	$ 8,829	$ —	$ 5,395	14,224
Accrued liabilities	22,926	—	—	22,926
Derivative fair value	991	—	—	991
Asset retirement obligation, current portion	1,750	—	—	1,750
Other current liabilities	1,346	—	—	1,346
Total Current Liabilities	35,842	—	5,395	41,237
Long-term Debt	7,100		148,000	155,100
Other Liabilities:				
Asset retirement obligation	157,294	—	16,810	174,104
Other liabilities	1,495	—	—	1,495
Total Other Liabilities	158,789	—	16,810	175,599
Commitments and Contingencies				
Partners' Capital:				
Partners' capital	572,788	18,745(a)	50,000	641,533
Total Partners' Capital	572,788	18,745	50,000	641,533
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 774,519	$ 18,745	$ 220,205	1,013,469

The accompanying notes are an integral part of these unaudited pro forma financial statements.

TXO PARTNERS, L.P.
Pro Forma Statements of Operations for the Year Ended December 31, 2023
(Unaudited)

(in thousands, except for per unit information)	TXO Partners Historical	EMEP Acquisition	Offering	Pro Forma
REVENUES				
Oil and condensate	$ 182,733	$ 81,629(b)	$ —	$ 264,362
Natural gas liquids	29,193	4,310	—	33,503
Gas	168,792	1,308	—	170,100
Total Revenues	380,718	87,247	—	467,965
EXPENSES				
Production	144,730	20,103	—	164,833
Exploration	151	—	—	151
Taxes, transportation and other	75,415	7,299	—	82,714
Depreciation, depletion, and amortization	44,288	26,493(c)	—	70,781
Impairment of long-lived assets	223,384	—	—	223,384
Accretion of discount in asset retirement obligation	8,644	1,209(d)	—	9,853
General and administrative	7,887	(2,016)	—	5,871
Total Expenses	504,499	53,088	—	557,587
OPERATING (LOSS) INCOME	(123,781)	34,159	—	(89,622)
OTHER INCOME (EXPENSE)				
Other income (expense)	23,756	(288)	—	23,468
Interest income	461	—	—	461
Interest expense	(4,423)	(12,439)(e)	—	(16,862)
Other Income	19,794	(12,727)	—	7,067
NET (LOSS) INCOME	$(103,987)	$ 21,432	$ —	$ (82,555)
NET INCOME PER COMMON UNIT (f)				
Basic	$ (3.47)	$ 8.57	$ —	$ (2.07)
Diluted	$ (3.47)	$ 8.57	$ —	$ (2.07)
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING (f)				
Basic	30,000	2,500	7,475	39,975
Diluted	30,000	2,500	7,475	39,975

The accompanying notes are an integral part of these unaudited pro forma financial statements.

TXO PARTNERS, L.P.
Pro Forma Statements of Operations for the Six Months Ended June 30, 2024
(Unaudited)

(in thousands, except for per unit information)	TXO Partners Historical	EMEP Acquisition	Offering	Pro Forma
REVENUES				
Oil and condensate	$ 80,833	$ 31,029(b)	$ —	$ 111,862
Natural gas liquids	13,172	2,099	—	15,271
Gas	30,742	152	—	30,894
Total Revenues	124,747	33,280	—	158,027
EXPENSES				
Production	69,522	10,187	—	79,709
Exploration	194	—	—	194
Taxes, transportation and other	28,774	3,365	—	32,139
Depreciation, depletion, and amortization	20,849	13,851(c)	—	34,700
Accretion of discount in asset retirement obligation	5,565	688(d)	—	6,253
General and administrative	7,245	(901)	—	6,344
Total Expenses	132,149	27,190	—	159,339
OPERATING (LOSS) INCOME	(7,402)	6,090	—	(1,312)
OTHER INCOME (EXPENSE)				
Other income	22,255	58	—	22,313
Interest income	247	—	—	247
Interest expense	(2,025)	(6,324)(e)	—	(8,349)
Other Income	20,477	(6,266)	—	14,211
NET (LOSS) INCOME	$ 13,075	$ (176)	$ —	$ 12,899
NET INCOME PER COMMON UNIT (f)				
Basic	$ 0.42	$ (0.07)	$ —	$ 0.32
Diluted	$ 0.42	$ (0.07)	$ —	$ 0.31
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING (f)				
Basic	30,869	2,500	7,475	40,844
Diluted	31,459	2,500	7,475	41,434

The accompanying notes are an integral part of these unaudited pro forma financial statements.

1. BASIS OF PRESENTATION, CORPORATE REORGANIZATION AND THE OFFERING

The historical financial information is derived from the financial statements of TXO Partners included elsewhere in this prospectus. For purposes of the unaudited pro forma balance sheet, it is assumed that the EMEP Acquisition and Offering had taken place on June 30, 2024. For purposes of the unaudited pro forma statements of operations, it is assumed all transactions had taken place on January 1, 2023.

2. PRO FORMA ADJUSTMENTS AND ASSUMPTIONS

TXO Partners made the following adjustments and assumptions in the preparation of the unaudited pro forma financial statements:

(a) Reflects estimated gross proceeds of $18.7 million from the issuance and sale of 975,000 shares of common units at an underwritten public offering price of $20.00 per unit, net of underwriting discounts and commissions of $0.8 million, in the aggregate, and the use of the net proceeds therefrom as partial payment of the cash portion of the EMEP Acquisition.

(b) Unless otherwise noted, adjustments below in items (c) – (e) reflect the historical financial statements Eagle Mountain Energy Partners and the historical statements of revenues and direct operating expenses of Vendera V4-ELM. LP., from the assets acquired and liabilities assumed in the EMEP Acquisition, as included elsewhere in this prospectus.

(c) Adjustment reflects additional depreciation, depletion, and amortization expense that would have been incurred with respect to the EMEP Acquisition, had such acquisitions occurred on January 1, 2023.

(d) Adjustment reflects additional accretion of discount in asset retirement obligation expense that would have been recorded with respect to the asset retirement obligation assumed in the EMEP Acquisition, had such acquisition occurred on January 1, 2023.

(e) Adjustment reflects increase in interest expense from the additional borrowings used to pay for the cash portion of the EMEP Acquisition had the acquisition closed on January 1, 2023. The average interest rate was 8.4% for the year ended December 31, 2023 and 8.6% for the six months ended June 30, 2024.

(f) Reflects basic and diluted income (loss) per common share for the issuance of 7,475,000 common units in the Offering and 2,500,000 common units in the EMEP Acquisition as shown below:

	Six months ended June 30, 2024	Year ended December 31, 2023
Basic		
Net income (loss)	$ 12,899	$ (82,555)
Weighted average common units outstanding	40,844	39,975
Basic earnings (loss) per share	$ 0.32	$ (2.07)
Diluted		
Numerator:		
Net income (loss)	$ 12,899	$ (82,555)
Effect of dilutive securities	—	—
Diluted net income (loss) attributable to stockholders	$ 12,899	$ (82,555)
Denominator:		
Basic weighted average shares outstanding	40,844	39,975
Effect of dilutive securities	590	— *(a)*
Diluted weighted average shares outstanding	41,434	39,975
Diluted earnings (loss) per share	$ 0.31	$ (2.07)

(a) – As there was a net loss for the period, any incremental shares would be anti-dilutive. As such, the potentially diluted shares totaling 545,000 were excluded from the calculation.

3. SUPPLEMENTARY DISCLOSURE OF OIL AND NATURAL GAS OPERATIONS

The following pro forma standardized measure of the discounted net future cash flows and changes applicable to TXO Partners' proved reserves reflect the effect of Texas state franchise taxes which TXO Partners is subject to. The future cash flows are discounted at 10% per year and assume continuation of existing economic conditions.

The standardized measure of discounted future net cash flows, in management's opinion, should be examined with caution. The basis for this table is the reserve studies prepared by independent petroleum engineering consultants, which contain imprecise estimates of quantities and rates of production of reserves. Revisions of previous year estimates can have a significant impact on these results. Also, exploration costs in one year may lead to significant discoveries in later years and may significantly change previous estimates of proved reserves and their valuation. Therefore, the standardized measure of discounted future net cash flow is not necessarily indicative of the fair value of TXO Partners' proved oil and natural gas properties.

The data presented should not be viewed as representing the expected cash flow from or current value of, existing proved reserves since the computations are based on a large number of estimates and assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. Actual future prices and costs are likely to be substantially different from the prices and costs utilized in the computation of reported amounts.

The following table provides a pro forma rollforward of the total proved reserves for the year ended December 31, 2023, as well as pro forma proved developed and proved undeveloped reserves at the beginning and end of the year, as if the acquisition reflected occurred on January 1, 2023.

Oil (MBbls)	TXO Partners Historical	EMEP Acquisition	Pro Forma
January 1, 2023	53,509.2	10,750.4	64,259.6
Extensions, additions and discoveries	71.7	1.7	73.4
Revisions	(11,628.5)	332.8	(11,295.7)
Production	(2,375.6)	(1,006.9)	(3,382.5)
Purchase in place	876.3	—	876.3
December 31, 2023	40,453.1	10,078.0	50,531.1
Proved Developed Reserves			
January 1, 2023	34,672.0	10,750.4	45,422.4
December 31, 2023	30,959.4	10,078.0	41,037.4
Proved Undeveloped Reserves			
January 1, 2023	18,837.2	—	18,837.2
December 31, 2023	9,493.7	—	9,493.7

Natural Gas Liquids (MBbls)	TXO Partners Historical	EMEP Acquisition	Pro Forma
January 1, 2023	21,932.4	2,290.1	24,222.5
Extensions, additions and discoveries	—	0.1	0.1
Revisions	(5,245.0)	(5.8)	(5,250.8)
Production	(1,231.8)	(192.4)	(1,424.2)
Purchase in place	27.4	—	27.4
December 31, 2023	15,483.0	2,092.0	17,575.0
Proved Developed Reserves			
January 1, 2023	20,723.6	2,290.1	23,013.7
December 31, 2023	15,110.9	2,092.0	17,202.9
Proved Undeveloped Reserves			
January 1, 2023	1,208.8	—	1,208.8
December 31, 2023	372.1	—	372.1

Natural Gas (MMcf)	TXO Partners Historical	EMEP Acquisition	Pro Forma
January 1, 2023	407,877.2	12,454.4	420,331.6
Extensions, additions and discoveries	7,050.2	0.6	7,050.8
Revisions	(121,848.5)	(242.2)	(122,090.7)
Production	(28,738.7)	(1,028.9)	(29,767.6)
Purchase in place	1,487.4	—	1,487.4
December 31, 2023	265,827.6	11,183.9	277,011.5
Proved Developed Reserves			
January 1, 2023	385,188.6	12,454.4	397,643.0
December 31, 2023	264,934.4	11,183.9	276,118.3
Proved Undeveloped Reserves			
January 1, 2023	22,688.6	—	22,688.6
December 31, 2023	893.2	—	893.2

Total (MBoe)	TXO Partners Historical	EMEP Acquisition	Pro Forma
January 1, 2023	143,421.1	15,116.3	158,537.4
Extensions, additions and discoveries	1,246.7	1.9	1,248.6
Revisions	(37,181.5)	286.6	(36,894.9)
Production	(8,397.2)	(1,370.8)	(9,768.0)
Purchase in place	1,151.6	—	1,151.6
December 31, 2023	100,240.7	14,034.0	114,274.7
Proved Developed Reserves			
January 1, 2023	119,593.7	15,116.3	134,710.0
December 31, 2023	90,226.0	14,034.0	104,260.0
Proved Undeveloped Reserves			
January 1, 2023	23,827.4	—	23,827.4
December 31, 2023	10,014.7	—	10,014.7

The pro forma standardized measure of discounted estimated future net cash flows was as follows as of December 31, 2023 (in thousands):

December 31, 2023 *(in thousands)*	TXO Partners Historical	EMEP Acquisition	Pro Forma
Future cash inflows	$ 4,101,171	$ 829,645	$ 4,930,816
Future costs:			
Production	(2,091,880)	(349,382)	(2,441,262)
Development	(353,191)	(66,659)	(419,850)
Income taxes	(2,143)	—	(2,143)
Future net cash flows	1,653,957	413,604	2,067,561
10% annual discount	(763,365)	(147,393)	(910,758)
Standardized measure	$ 890,592	$ 266,211	$ 1,156,803

The change in the pro forma standardized measure of discounted estimated future net cash flows were as follows for 2023 (in thousands):

December 31, 2023	TXO Partners Historical	EMEP Acquisition	Pro Forma
Standardized measure, beginning of period	$ 1,969,818	$ 366,356	$ 2,336,174
Revisions:			
Prices and costs	(1,053,775)	(21,900)	(1,075,675)
Quantity estimates	(147,398)	(18,328)	(165,726)
Income tax	2,250	—	2,250
Future development costs	(106)	—	(106)
Accretion of discount	196,982	36,636	233,618
Production rates and other	22,868	(41,184)	(18,316)
Net revisions	(979,179)	(44,776)	(1,023,955)
Additions and discoveries	(8,047)	(138)	(8,185)
Production	(137,393)	(55,231)	(192,624)
Development costs	29,820	—	29,820
Purchases in place	15,573	—	15,573
Net change	(1,079,226)	(100,145)	(1,179,371)
Standardized measure, end of period	$ 890,592	$ 266,211	$ 1,156,803