As confidentially submitted to the Securities and Exchange Commission on July 14, 2022

Registration No. 333-

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Confidential Draft Submission No. 1

Form S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

MorningStar Partners, L.P.*

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**32-0368858**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification No.)

400 West 7th Street
Fort Worth, Texas 76102
(817) 334-7800
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Brent W. Clum
President of Business Operations and Chief Financial Officer
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Approximate date of commencement of proposed sale of the securities to the public:
As soon as practicable after the effective date of this Registration Statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box: ☐

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 7(a)(2)(B) of the Securities Act. ☐

The registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment that specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until this Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

* MorningStar Partners, L.P. is the registrant filing this Registration Statement with the Securities and Exchange Commission. Prior to the closing of the offering, MorningStar Partners, L.P. will be renamed TXO Energy Partners, L.P. in connection with the reorganization transactions described in the Registration Statement.

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SUBJECT TO COMPLETION, DATED , 2022

PRELIMINARY PROSPECTUS

TXO Energy Partners, L.P.

Common Units

Representing Limited Partner Interests

We are a Delaware limited partnership focused on the acquisition, development, optimization and exploitation of conventional oil, natural gas and natural gas liquid reserves in North America. This is the initial public offering of our common units. No public market currently exists for our common units. We expect the initial public offering price to be between $ and $ per common unit. We are an "emerging growth company" as that term is used in the Jumpstart Our Business Startups Act. We have applied to list our common units on the NYSE under the symbol "TXO."

Investing in our common units involves risks. See "Risk Factors" beginning on page 30.

These risks include the following:

- We may not have sufficient available cash to pay any quarterly distribution on our common units following the establishment of cash reserves and payment of expenses.
- The volatility of oil, natural gas and NGL prices due to factors beyond our control greatly affects our financial condition, results of operations and cash available for distribution.
- Unless we replace the reserves we produce, our revenues and production will decline, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders.
- We are subject to stringent federal, state and local laws and regulations related to environmental and occupational health and safety issues that could adversely affect the cost or feasibility of conducting our operations or expose us to significant liabilities.
- Our general partner and its affiliates own a controlling interest in us and will have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.
- Our unitholders have limited voting rights and are not entitled to elect our general partner or its board of directors, which could reduce the price at which our common units will trade.
- Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.
- Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation for federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders could be reduced.
- Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

PRICE $ PER COMMON UNIT

	Per Common Unit	Total
Public offering price	$	$
Underwriting discount		
Proceeds, before expenses		

We have granted the underwriters a 30-day option to purchase up to an additional common units on the same terms and conditions as set forth above if the underwriters sell more than common units in this offering.

The underwriters expect to deliver the common units on or about , 2022.

Book-Running Manager

Raymond James

, 2022

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Neither we nor the underwriters have authorized anyone to provide you with any information or to make any representations other than those contained in this registration statement. We and the underwriters take no responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you. You should not assume that the information contained in this registration statement is accurate as of any date other than the date on the front cover of this registration statement. Our business, financial condition, results of operations and prospects may have changed since such dates. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where an offer or sale is not permitted.

Until , 2022 (25 days after the date of this prospectus), all dealers that buy, sell or trade our common units, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. Please read "Risk Factors" and "Forward-Looking Statements."

INDUSTRY AND MARKET DATA

The market data and certain other statistical information included in this prospectus are based on a variety of sources, including independent industry publications, government publications and other published independent sources. Some data is also based on our good faith estimates, which have been derived from management’s knowledge and experience in the industry in which we operate. Although we have not independently verified the accuracy or completeness of the third-party information included in this prospectus, based on management’s knowledge and experience, we believe that these third-party sources are reliable and that the third-party information included in this prospectus or in our estimates is accurate and complete. While we are not aware of any misstatements regarding the market, industry or similar data presented herein, such data involve risks and uncertainties and are subject to change based on various factors, including those discussed under the headings “Forward-Looking Statements” and “Risk Factors” in this prospectus.

TRADEMARKS AND TRADE NAMES

We own or have rights to various trademarks, service marks and trade names that we use in connection with the operation of our business. This prospectus may also contain trademarks, service marks and trade names of third parties, which are the property of their respective owners. Our use or display of third parties’ trademarks, service marks, trade names or products in this prospectus is not intended to, and does not imply a relationship with, or endorsement or sponsorship by us. Solely for convenience, the trademarks, service marks and trade names referred to in this prospectus may appear without the ®, TM or SM symbols, but such references are not intended to indicate, in any way, that we will not assert, to the fullest extent under applicable law, our rights or the right of the applicable licensor to these trademarks, service marks and trade names.

PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. Because this is a summary, it may not contain all of the information that may be important to you and to your investment decision. The following summary is qualified in its entirety by the more detailed information and financial statements and notes thereto included elsewhere in this prospectus. You should read the entire prospectus carefully and should consider, among other things, the matters set forth in "Risk Factors," "Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our historical and unaudited pro forma consolidated financial statements, the Chevron Vacuum Acquisition historical statement of revenues and direct operating expenses and the related notes to each of those financial statements included elsewhere in this prospectus before deciding to invest in our common units.

The information presented in this prospectus assumes (i) an initial public offering price of $ per common unit (the mid-point of the price range set forth on the cover of this prospectus) and (ii) that the underwriters do not exercise their option to purchase up to an additional common units, unless otherwise indicated. As used in this prospectus, the term "our general partner" refers to TXO Energy GP, LLC, a Delaware limited liability company, and the terms "partnership," "we," "our," "us" or similar terms refer to MorningStar Partners, L.P., to be renamed prior to the closing of this offering to TXO Energy Partners, L.P., a Delaware limited partnership ("TXO Energy Partners") and its subsidiaries. We include a glossary of some of the oil and natural gas terms and other terms used in this prospectus in Appendix B. Our estimated proved reserve information included in this prospectus are based on reports prepared by our reservoir engineering staff and evaluated by Cawley, Gillespie & Associates, Inc., our independent reserve engineers, and a summary thereof is included in this prospectus in Appendix C.

TXO Energy Partners

Overview

We are focused on the acquisition, development, optimization and exploitation of conventional oil, natural gas, and natural gas liquid reserves in North America. Our management team has significant industry experience acquiring and exploiting conventional oil and natural gas properties in multiple resource plays and basins. As a result, our operations focus primarily on enhancing the development and operation of producing properties through our concentration on efficiency and optimizing exploitation of current wells. Our current acreage positions are concentrated in the Permian Basin of West Texas and New Mexico and the San Juan Basin of New Mexico and Colorado, each of which we believe is characterized by low geologic risk, low decline rates and high recoveries relative to drilling and completion costs.

We intend to make quarterly distributions on our common units of all our cash available for distribution at the end of each such quarter. We believe the low decline nature of our reserves and the relatively low-cost expense to maintain production combined with our zero to low leverage profile will allow us to make relatively consistent quarterly distributions. The amount of cash flow from operations available for distribution with respect to any quarter, however, will be dependent on the then-prevailing commodity prices. To mitigate the risk associated with volatile commodity prices and to further enhance the stability of our cash flow available for distributions, from time to time we may opportunistically hedge a portion of our production volumes at prices we deem attractive to mitigate our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales.

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We seek to maintain a flat to low growth production profile through a combination oflow-risk development and exploitation of our existing properties, generally funded by cash flow from operating activities and future acquisitions of producing properties. We believe this will allow us to increase our reserves and production and, over time, to increase distributions to our unitholders.

The members of our management team have an average of 34 years' experience in the oil and gas industry and previously held executive roles at XTO Energy Inc. ("XTO"). Our management team has successfully executed on a strategy of acquiring and exploiting long-lived and low decline assets for more than 30 years, completing hundreds of acquisitions totaling over $15 billion. Additionally, our Chief Executive Officer, Bob Simpson, has a greater than 45-year history in the oil and gas industry. Mr. Simpson founded Cross Timbers Oil company in 1986 (subsequently named XTO Energy) and served as Chief Executive Officer and Chairman over the life of the company, culminating with a sale to ExxonMobil Corporation ("Exxon") for $41 billion in 2009. Additionally our management team has collectively invested more than $500 million in us since our inception. We believe our management team has the experience, expertise and commitment to create significant value for our unitholders in the form of cash distributions combined with growth in revenues and production.

As of December 31, 2021, our assets consisted of approximately 846,000 gross (370,000 net) leasehold and mineral acres located primarily in the Permian Basin and San Juan Basin. As of December 31, 2021, our total estimated proved reserves were approximately 130 MMBoe, of which approximately 37% were oil and approximately 82% were proved developed, both on a Boe basis. In the first quarter of 2022, we produced an average of approximately 23,077 Boe/d, approximately 72% of which came from assets operated by us.

The following tables present our historical estimated oil and natural gas reserves and PV-10 as of December 31, 2021.

	Estimated Proved Reserves as of December 31, 2021 (1)			
	SEC Pricing Proved Developed Reserves (MBoe)(2)	SEC Pricing Proved Reserves (MBoe)	NYMEX Pricing Proved Developed Reserves (MBoe)(3)	NYMEX Pricing Proved Reserves (MBoe)(3)
Permian Basin	34,790.0	54,715.2	35,541.8	55,527.7
San Juan Basin	66,735.2	66,735.2	72,973.5	72,973.5
Other	4,986.1	8,357.5	5,546.5	8,917.9
Total	106,511.3	129,807.9	114,061.8	137,419.1

(1) Presented on an oil-equivalent basis using a conversion of six thousand cubic feet of natural gas to one stock tank barrel of oil. This conversion is based on energy equivalence and not on price or value equivalence.

(2) SEC pricing, as required by the rules and regulations of the SEC, is the unweighted arithmetic average of the first-day-of-the-month price for each month within such period using published benchmark oil and gas prices, unless prices are defined by contractual arrangements.

(3) Using NYMEX forward-month contract pricing in effect as of June 15, 2022. We have included this reserve sensitivity because we believe that the use of NYMEX forward-month prices provides investors with additional useful information about our reserves. For more information regarding our use of NYMEX Pricing, please see "—Summary of Reserve, Production and Operating Data—Summary of Reserves as of December 31, 2021 Based on NYMEX Pricing."

(in millions)	SEC Pricing Proved Developed PV-10(1)	SEC Pricing Proved PV-10(3)	NYMEX Pricing Proved Developed PV-10(4)	NYMEX Pricing Proved PV-10(4)
	Estimated PV-10 as of December 31, 2021(2)			
Permian Basin	$ 486.5	$ 718.9	$ 694.1	$ 984.2
San Juan Basin	$ 254.2	$ 254.2	$ 480.4	$ 480.4
Other	$ 31.5	$ 44.2	$ 59.3	$ 80.0
Total	$ 772.2	$ 1,017.3	$ 1,233.8	$ 1,544.6

(1) SEC pricing, as required by the rules and regulations of the SEC, is the unweighted arithmetic average of the first-day-of-the-month price for each month within such period using published benchmark oil and gas prices, unless prices are defined by contractual arrangements."
(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Please see "Non-GAAP Financial Measures—Standardized Measure" for a reconciliation to its nearest GAAP financial measure.
(3) Presented on an oil-equivalent basis using a conversion of six thousand cubic feet of natural gas to one stock tank barrel of oil. This conversion is based on energy equivalence and not on price or value equivalence.
(4) Using NYMEX forward-month contract pricing in effect as of June 15, 2022. We have included this reserve sensitivity because we believe that the use of NYMEX forward-month prices provides investors with additional useful information about our reserves. For more information regarding our use of NYMEX Pricing, please see "—Summary of Reserve, Production and Operating Data—Summary of Reserves as of December 31, 2021 Based on NYMEX Pricing."

The following table summarizes information regarding our active well count and development locations included in our reserve report as of December 31, 2021.

	As of December 31, 2021									
	Active Oil and Natural Gas Wells		Active CO_2 Injection Wells		Conventional PUD Locations(1)		Recomplete Locations(2)		Workover Locations(3)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin	4,046	657.7	57	40.3	233	104.0	51	32.8	23	22.6
San Juan Basin	11,379	1,094.3	—	—	—	—	—	—	—	—
Other	3,012	88.4	—	—	4	1.8	—	—	—	—
Total	18,437	1,840.4	57	40.3	237	105.8	51	32.8	23	22.6

(1) Approximately 97% of our wells are drilled conventionally. However, from time to time a small number of wells are horizontally completed.
(2) Well locations we believe can be recompleted to another producing zone or zones.
(3) Well locations where we believe a currently completed zone can be improved or restored by performing remedial workovers.

Our Properties

Permian Basin

We acquired our initial 79,970 gross leasehold and mineral acres in the Permian Basin in 2012 and 2013. We subsequently acquired 11,929 additional gross leasehold acres through leasing and multiple bolt-on acquisitions. In November 2021, we acquired producing properties including 24,052 gross leasehold acres and a CO_2 processing plant in the Permian Basin within New Mexico and CO_2 assets in Colorado (the "Chevron Vacuum Acquisition") from Chevron Corporation

(“Chevron”). In December 2021, we acquired additional producing properties including 21,112 gross leasehold acres in the Permian Basin within Texas from Chevron (the “Chevron Andrews Parker Acquisition”). We refer to these together as the “Chevron Acquisitions.” As of March 31, 2022, we had 79 (gross) active CO_2 injection wells. Production from our CO_2 wells was 15.5 MMcf/d during the first quarter of 2022.

Our management team believes the development and exploitation of conventional assets in the Permian Basin is among the most economic oil and natural gas plays in the United States. Since completing our 2021 acquisitions, we have focused our efforts on returning wells to production as well as on other low-risk maintenance projects. As we gain a greater understanding of these recently acquired assets, we expect to increase our drilling and recompletion work. Substantially all of our acreage in the Permian Basin is held by production which means we do not have to drill any wells to maintain ownership of our leases. Based on current commodity prices, we expect to drill or participate in the drilling of approximately 20 gross wells in the Permian Basin during the remainder of 2022 and approximately 9 gross wells in 2023. We expect to recomplete 18 gross wells in the Permian Basin in 2022 and approximately 22 gross wells in 2023. We expect to return 25 gross wells to production in the Permian Basin in 2022 and 23 gross wells in 2023. As of December 31, 2021, our decline rate for our Permian Basin properties over the next 12 months is approximately 7%.

San Juan Basin

We acquired our initial 175,376 gross leasehold and mineral acres in the San Juan Basin in 2012 and 2013. We subsequently acquired 273,187 additional gross leasehold and mineral acres in June 2020.

Our San Juan acreage includes substantial, predictable, low-decline natural gas production that provides for relatively stable cash flows. As of December 31, 2021, our decline rate for our San Juan Basin properties over the next 12 months is approximately 10%. Our existing production comes from primarily coalbed methane wells, in which we own 363,358 gross acres. Substantially all of our acreage in the San Juan Basin is held by production. Additionally, we own 85,205 gross acres in New Mexico in the Mancos Shale. We believe our Mancos Shale properties offer us significant potential upside that is held by production.

Based on current commodity prices, we expect to drill or participate in the drilling of approximately 13 gross wells in the San Juan Basin during the remainder of 2022 and approximately 4 gross wells in 2023. We do not expect to recomplete any gross wells in the San Juan Basin in 2022 and 2023. We expect to return 10 gross wells to production in the San Juan Basin in 2022 but none in 2023.

For the three months ended March 31, 2022, our consolidated revenues were derived 50% from oil revenues, 38% from natural gas revenues and 12% from NGL revenues, in each case excluding the unrealized effects of our commodity derivative contracts. After giving effect to unrealized commodity derivative contracts, our revenues were derived 27% from oil revenues, 106% from natural gas revenues and (33)% from NGL. For the three months ended March 31, 2022, our total average production was 23,077 Boe/d (approximately 25% oil, 61% natural gas, and 14% NGLs). Over the same period, our average production in the Permian Basin was 6,673 Boe/d (approximately 85% oil, 4% natural gas, and 11% NGLs) and our average production in the San Juan Basin was 14,962 Boe/d (approximately 1% oil, 82% natural gas, and 17% NGLs).

Development Plan and Capital Budget

Historically, our business plan has focused on acquiring and then exploiting producing assets. Funding sources for our acquisitions have included proceeds from bank borrowings, cash from our partners and cash flow from operating activities. Our development budget is approximately $30.0 million for 2022 (of which $ 0.7 million has been incurred as of March 31, 2022) and approximately $30.0 million for 2023. Much of our development time and capital is spent on workovers, recompletions and field optimizations of existing assets. We expect to use the additional information derived from this exploitation to inform our decisions about additional drilling opportunities to pursue, either in recently acquired assets or new acquisitions. However, over the next 24 months we anticipate approximately half of our development activity will be focused on drilling new wells, virtually all of which we expect to be conventional, vertical wells.

We expect to allocate most of our remaining 2022 budget and the majority of our 2023 budget to projects focused on enhancing existing production. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2022 and 2023 capital development programs from cash flow from operations and the net proceeds of this offering. We increased our 2021 capital program to $8.1 million compared to $5.5 million in 2020, primarily in response to the improved oil price environment and the improving global and national economic environment.

During 2021 we drilled 4 gross wells in the Permian Basin and 6 gross wells in the San Juan Basin. Additionally, during 2021 we recompleted 6 gross wells in the Permian Basin and 6 gross wells in the San Juan Basin.

During 2022, we expect to spend approximately $20 million to drill 33 gross wells (18 net wells) and related equipment, $4 million on recompletions of existing wells and $6 million on remedial workovers and other maintenance projects. We expect to spend approximately $20 million in the Permian Basin and approximately $10 million in the San Juan Basin in 2022.

Our Business Strategies

Our primary business objective is to generate relatively consistent cash flow to enable us to make quarterly cash distributions from our available cash to our unitholders and, over time, to increase our quarterly cash distributions. To achieve our objective, we intend to execute the following business strategies:

- **Focus on long-lived, low decline conventional assets.** We believe that by focusing on the exploitation of our existing assets, we can maintain current production using a portion of our operating cash flow, while utilizing the remainder of our operating cash flow to acquire additional assets to exploit and make distributions to our unitholders.

- **Maximize ultimate hydrocarbon recovery from our assets through enhancement and optimization of producing properties.** We continuously seek efficiencies in our drilling, completion and production techniques to optimize ultimate resource recoveries, rates of return and cash flows. We will continue to work to unlock additional value and will allocate capital towards next generation technologies where applicable. In addition, we intend to take advantage of under-development in basins where we operate by expanding our geologic investigation of additional producing horizons on our acreage and adjacent acreage. We seek to expand our development beyond our known productive areas to add reserves to our inventory at attractive all-in costs.

- **Focus on making cash distributions to, and providing long term value for, our unitholders.** Our primary goal is to maximize investor returns through cash distributions and flat to low growth. We intend to grow production and acreage over time, but our primary focus will be providing relatively consistent quarterly cash distributions from our available cash to our unitholders and increasing the long-term value of our common units.

- **Maintain financial flexibility with a conservative capital structure and ample liquidity.** We intend to conduct our operations primarily through cash flow generated from operations with a focus on maintaining a disciplined balance sheet with little to no outstanding debt. Due to our strong operating cash flows and liquidity, we have substantial flexibility to fund our capital budget and to potentially accelerate our drilling program as conditions warrant. Our focus is on the economic extraction of hydrocarbons while maintaining a prudent leverage ratio and strong liquidity profile. Although we may use leverage to make accretive acquisitions, we will do so with the long-term goal of remaining substantially debt free. Further, we expect that our hedging strategy will reduce our exposure to commodity price volatility.

- **Execute attractive acquisitions and optimize assets through effective integration.** Our management team has a history of successfully identifying, acquiring and optimizing assets over the past three decades. We believe our acreage positions in the Permian Basin and San Juan Basin provide opportunities to increase production and reserves through the implementation of mechanical and operational improvements, workovers, behind-pipe completions, secondary and tertiary recovery operations, new development wells and other development activities. We plan to use the expertise of our management team to strategically acquire properties that complement our operations.

Our Strengths

We believe that the following strengths will allow us to successfully execute our business strategies:

- **Experienced and personally invested management team with an extensive track record of value creation.** We believe our management team's significant industry experience is a distinguishing competitive advantage. The members of our management team have an average of 34 years' experience in the oil and gas industry and have previously held executive roles at XTO. Our management team has successfully executed on a strategy of acquiring and exploiting long-lived and low decline assets for more than 30 years. Members of our management team have collectively personally invested more than $500 million in us since our inception.

- **Stable, long-lived, conventional asset base with low production decline rates.** The majority of our interests are in properties that have produced oil and natural gas for decades. As a result, the geology and reservoir characteristics are well understood, and new development well results are generally predictable, repeatable and present lower risk than unconventional resource plays. Our assets are characterized by long-lived reserves with low production decline rates, a stable development cost structure and low-geologic risk developmental drilling opportunities with predictable production profiles. For example, as of December 31, 2021, our decline rate over the next twelve months is approximately 9%.

- **Ability to source, integrate and optimize acquisitions.** Our management team has demonstrated the ability to source and integrate acquisitions of various sizes. While at XTO, our management team completed hundreds of acquisitions for over $15 billion in consideration and successfully integrated such acquisitions, ultimately driving significant returns for shareholders. We have successfully drawn on this experience to identify and complete multiple acquisitions to establish our anchor positions in the Permian Basin and San Juan Basin, including our recent Chevron Acquisitions. We expect that our expertise in sourcing and completing acquisitions will allow us to successfully execute additional bolt-on acquisitions in our existing operating areas and, if and when appropriate, additional opportunistic acquisitions.

- **Conservatively capitalized balance sheet, strong liquidity profile and financial flexibility.** We have a strong and conservative financial position that allows us to effectively allocate capital and grow our reserves and production. Due to the significant existing vertical production and the predictable low-decline profiles associated with our existing production, our business generates significant operating cash flows. After this offering, we expect to have little to no debt and substantial liquidity, which will provide us with further financial flexibility to fund our capital expenditures and grow production and reserves as part of our existing strategic plan. We may also opportunistically hedge to protect our future operating cash flows from volatility in commodity prices.

Risk Factor Summary

An investment in our common units involves risks associated with our business, our partnership structure and the tax characteristics of our common units, among other things. You should carefully consider the risks described in "Risk Factors" and the other information in this prospectus before investing in our common units. Some of the most significant challenges and risks we face include the following:

Risks Related to Cash Distributions

- We may not have sufficient available cash to pay any quarterly distribution on our common units following the establishment of cash reserves and payment of expenses.

- The assumptions underlying the forecast of cash available for distribution we include in "Our Cash Distribution Policy and Restrictions on Distributions" may prove inaccurate and are subject to significant risks and uncertainties that could cause actual results to differ materially from our forecasted results.

Risks Related to Our Business and the Oil, Natural Gas and NGL Industry

- The volatility of oil, natural gas and NGL prices due to factors beyond our control greatly affects our financial condition, results of operations and cash available for distribution.

- Unless we replace the reserves we produce, our revenues and production will decline, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders.

- If commodity prices decline and remain depressed for a prolonged period, production from a significant portion of our properties may become uneconomic and cause downward adjustments of our reserve estimates and write downs of the value of such properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

- Drilling for and producing oil, natural gas and NGLs are high-risk activities with many uncertainties that could adversely affect our business, financial condition, results of operations and cash distributions to unitholders.
- We operate certain of our properties through a joint venture over which we have shared control.
- Declining general economic, business or industry conditions and inflation may have a material adverse effect on our results of operations, liquidity and financial condition.
- Events outside of our control, including an epidemic or outbreak of an infectious disease, such asCOVID-19, or the threat thereof, could have a material adverse effect on our business, liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units.
- We use derivative instruments to economically hedge exposure to changes in commodity price and, as a result, are exposed to credit risk and market risk.
- Our Credit Facility has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders.
- Reserve estimates depend on many assumptions that may ultimately be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Risks Related to Environmental and Regulatory Matters

- We are subject to stringent federal, state and local laws and regulations related to environmental and occupational health and safety issues that could adversely affect the cost or feasibility of conducting our operations or expose us to significant liabilities.
- Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil, natural gas and NGL exploration and production activities, and reduce demand for the oil, natural gas and NGLs we produce.

Risks Inherent in an Investment in Us

- Our general partner and its affiliates own a controlling interest in us and will have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

- Our partnership agreement replaces our general partner's fiduciary duties to our unitholders with contractual standards governing its duties, and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

- Units held by persons who our general partner determines are not eligible holders will be subject to redemption.

- Our unitholders have limited voting rights and are not entitled to elect our general partner or the Board, which could reduce the price at which our common units will trade.

- Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.

- Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.

- Control of our general partner may be transferred to a third party without unitholder consent.

- Our general partner may elect to convert or restructure us from a partnership to an entity taxable as a corporation for U.S. federal income tax purposes without unitholder consent and without taking into account the immediate and long-term tax consequences of such transaction to unitholders, which in some cases may be material.

- We may not make cash distributions during periods when we record net income.

- We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval.

- The NYSE does not require a publicly traded partnership like us to comply, and we do not intend to comply, with certain of its governance requirements generally applicable to corporations.

Tax Risks to Common Unitholders

- Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation for federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders could be reduced.
- Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Reorganization Transactions and Partnership Structure

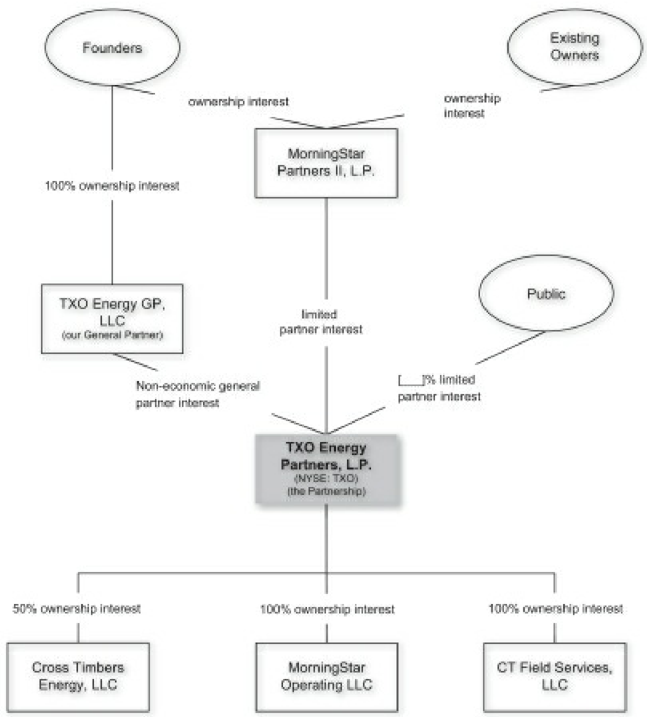
Immediately prior to the closing of this offering:

- holders of our existing equity interests (the "Existing Owners"), which include Bob R. Simpson, our Chief Executive Officer and Chairman of the Board, Brent W. Clum, our President of Business Operations and Chief Financial Officer, Keith A. Hutton, our President of Production and Development, Scott T. Agosta, our Chief Accounting Officer, Vaughn O. Vennerberg II, our Executive Vice President, and Timothy L. Petrus, our former Executive Vice President (collectively, our "Founders), in TXO Energy Partners will contribute all of the outstanding equity interests into a new parent company, MorningStar Partners II, L.P., a Delaware limited partnership; and

- we will amend our partnership agreement to make TXO Energy GP, LLC, a Delaware limited liability company, our new general partner.

Ownership and Organizational Structure of TXO Energy Partners

The diagram below depicts our organization and ownership after giving effect to the offering and the related reorganization transactions and assumes that the underwriters do not exercise their option to purchase additional common units.



Management of TXO Energy Partners

We are managed and operated by the board of directors (the "Board") and executive officers of our general partner, TXO Energy GP, LLC. Our unitholders will not be entitled to elect our general partner or its directors or otherwise participate in our management or operation. For information about the executive officers and directors of our general partner, please read "Management."

Our general partner has one class of member interests, all of which is owned by our Founders. As a result, the Founders control our general partner and will be entitled to appoint its entire board of directors.

Our operations are conducted through, and our assets are currently owned by, various subsidiaries. Immediately prior to the closing of this offering, we and our general partner will enter into a services agreement with a subsidiary of MorningStar Partners II, L.P. (the "Services Company"), pursuant to which the Services Company will provide administrative and operating services to us for our field operations. Although all of the employees that conduct our business are either employed by our general partner or the Services Company, we sometimes refer to these individuals in this prospectus as our employees.

We conduct a substantial amount of our operations through Cross Timbers Energy, LLC ("Cross Timbers"), a joint venture owned 50% by us and 50% by certain affiliates of Exxon and XTO, which we refer to collectively as the "XTO Entities." We account for our undivided interest in our investment in Cross Timbers using the proportionate consolidation method, pursuant to which we consolidate our proportionate share of assets (including reserves), liabilities, revenues and expenses of the joint venture. In accordance with the limited liability company agreement governing Cross Timbers (the "JV LLCA"), Cross Timbers is managed by us and governed by a member management committee comprised of six members, three of whom are appointed by us and three of whom are appointed by the XTO Entities.

Implications of Being an Emerging Growth Company

We are an "emerging growth company" as defined in the Jumpstart Our Business Startups Act (the "JOBS Act"). For as long as we are an emerging growth company, unlike other public companies that are not emerging growth companies under the JOBS Act, we are not required to:

- provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act;
- provide more than two years of audited financial statements and related management's discussion and analysis of financial condition and results of operations nor more than two years of selected financial data;
- comply with any new requirements adopted by the Public Company Accounting Oversight Board (the "PCAOB") requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; or
- provide certain disclosure regarding executive compensation required of larger public companies required by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act").

We will cease to be an emerging growth company upon the earliest of:

- the last day of the fiscal year in which we have $1.07 billion or more in annual revenues (as such amount may be adjusted by the SEC for inflation);
- the date on which we become a "large accelerated filer" (the fiscalyear-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30);
- the date on which we issue more than $1.0 billion ofnon-convertible debt over a three-year period; or
- the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended (the "Securities Act"), for complying with new or revised accounting standards. We have elected to avail ourselves of the provision of the JOBS Act that permits emerging growth companies to take advantage of an extended transition period to comply with new or revised accounting standards applicable to public companies. As a result, we will not be subject to new or revised accounting standards at the same time as other public companies that are not emerging growth companies. We intend to take advantage of the other exemptions discussed above, both in this prospectus and in future filings with the U.S. Securities and Exchange Commission (the "SEC"). Accordingly, the information contained herein and that we provide to our unitholders from time to time may be different than the information you receive from other public companies. For additional information, see the section titled "Risk Factors—Risks Inherent in an Investment in Us—Taking advantage of the longer phase-in periods for the adoption of new or revised financial accounting standards applicable to emerging growth companies may make our common units less attractive to investors." We are an "emerging growth company" and the reduced disclosure requirements applicable to emerging growth companies may make our common units less attractive to investors.

Principal Executive Offices and Internet Address

Our principal executive offices are located at 400 W 7th St., Fort Worth, TX 76102 and our telephone number at that address is (817) 334-7800. Our website address is and will be activated in connection with the closing of this offering. We expect to make our periodic reports and other information filed with or furnished to the SEC available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on, or otherwise accessible through, our website or any other website is not incorporated by reference into, and does not constitute a part of, this prospectus.

Summary of Conflicts of Interest and Duties

Under our partnership agreement, our general partner has a duty to manage us in a manner it believes is not adverse to our best interests. However, because our general partner is wholly owned by the Founders, the officers and directors of our general partner also have a duty to manage the business of our general partner in a manner that is beneficial to the Founders. As a result of this relationship, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our general partner and its affiliates, including the Founders, on the other hand. For example, our general partner is entitled to make determinations that affect our ability to generate the cash flow necessary to make cash distributions to our unitholders, including determinations related to:

- purchases and sales of oil and natural gas properties and other acquisitions and dispositions, including whether to pursue acquisitions that may also be suitable for the Founders or any affiliate of the Founders;
- the manner in which our business is operated;
- the level of our borrowings;
- the amount, nature and timing of our capital expenditures; and
- the amount of cash reserves necessary or appropriate to satisfy our general, administrative and other expenses and debt service requirements and to otherwise provide for the proper conduct of our business.

For a more detailed description of the conflicts of interest and duties of our general partner, please read "Risk Factors—Risks Inherent in an Investment in Us" and "Conflicts of Interest and Duties."

Our partnership agreement can generally be amended with the consent of our general partner and the approval of the holders of a majority of our outstanding common units (including any common units held by affiliates of our general partner). Upon consummation of this offering, our general partner will continue to be owned by the Founders, who collectively with the other Existing Owners will own and control the voting of an aggregate of approximately % of our outstanding common units. Assuming that we do not issue any additional common units and the Existing Owners do not transfer their units, the Existing Owners will have the ability to amend our partnership agreement, including our policy to distribute all of our available cash to our unitholders, without the approval of any other unitholders. Please see "Risk Factors—Risks Inherent in an Investment in Us" and "The Partnership Agreement—Amendment of the Partnership Agreement."

Delaware law provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties owed by the general partner to limited partners and the partnership. Our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of our general partner and contractual methods of resolving conflicts of interest. The effect of these provisions is to restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of its fiduciary duties. Our partnership agreement also provides that affiliates of our general partner, including the Founders and their affiliates, are not restricted from competing with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement, and pursuant to the terms of our partnership agreement, each holder of common units consents to various actions and potential conflicts of interest contemplated in our partnership agreement that might otherwise be considered a breach of fiduciary or other duties under Delaware law. Please read "Conflicts of Interest and Duties—Duties of Our General Partner" for a description of the fiduciary duties imposed on our general partner by Delaware law, the replacement of those duties with contractual standards under our partnership agreement and certain legal rights and remedies available to holders of our common units. For a description of our other relationships with our affiliates, please read "Certain Relationships and Related Party Transactions."

The Offering

Common units offered by us	common units representing limited partner interests (common units if the underwriters exercise in full their option to purchase additional common units).
Units outstanding after this offering	common units representing % limited partner interests in us (common units if the underwriters exercise their option in full to purchase additional common units).
Use of proceeds	We intend to use the expected net proceeds of approximately $ million from this offering ($ million if the underwriters exercise their option to purchase additional units in full), based upon the assumed initial public offering price of $ per common unit, after deducting underwriting discounts and estimated expenses, to repay in full amounts outstanding under our revolving credit facility (our "Credit Facility"), with any remaining amounts to be used for working capital and general partnership purposes.
Cash distributions	Within 60 days after the end of each quarter (other than the fourth quarter) and within 90 days after the end of the fourth quarter, beginning with the quarter ending , 2022, we expect to pay distributions of our available cash to unitholders of record on the applicable record date. The board of directors of our general partner will adopt a policy pursuant to which distributions for each quarter will be paid to the extent we have sufficient cash after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. Our ability to pay such cash distributions is subject to various restrictions and other factors described in more detail under the caption "Our Cash Distribution Policy and Restrictions on Distributions." We will prorate the amount of our distribution payable for the period from the closing of this offering through , 2022, based on the actual length of that period. Our partnership agreement generally provides that we will distribute all available cash each quarter to the holders of common units, pro rata. Pro forma cash available for distribution generated during the year ended December 31, 2021 was approximately $ million. As a result, for the year ended December 31, 2021, we would have generated available cash sufficient to pay a cash distribution of $ per unit per quarter ($ on an annualized basis). For a calculation of our

	ability to pay distributions to our unitholders based on our pro forma results for the year ended December 31, 2021 and twelve month period ended March 31, 2022, please read "Our Cash Distribution Policy and Restrictions on Distributions—Unaudited Pro Forma Available Cash for the Year Ended December 31, 2021 and the Twelve Months Ended March 31, 2022." We believe, based on our financial forecast and the related assumptions included under "Our Cash Distribution Policy and Restrictions on Distributions—Estimated Cash Available for Distribution for the Twelve Months Ending June 30, 2023," that we will have sufficient cash available for distribution to make cash distributions of $ per unit on all common units for the four quarters ending June 30, 2023. We will not have a minimum quarterly distribution nor is there any guarantee that we will make any particular amount of distributions or any distributions to our unitholders in any quarter. Please read "Our Cash Distribution Policy and Restrictions on Distributions."
Issuance of additional units	We can issue an unlimited number of additional units, including units that are senior to the common units in right of distributions, liquidation and voting, on terms and conditions determined by our general partner, without the approval of our unitholders. Please read "Units Eligible for Future Sale" and "The Partnership Agreement—Issuance of Additional Partnership Interests."
Limited voting rights	Our general partner will manage us and operate our business. Unlike stockholders of a corporation, our unitholders will have only limited voting rights on matters affecting our business. Our unitholders will have no right to elect our general partner or its board of directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least 66⅔% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class. Upon consummation of this offering, the Existing Owners will own an aggregate of approximately % of our common units and, therefore, will be able to prevent the removal of our general partner. Please read "The Partnership Agreement—Limited Voting Rights."
Limited call right	If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a purchase price not less than the then-current market price of the common units, as calculated pursuant to the terms of our partnership

	agreement. Upon consummation of this offering, the Existing Owners will own an aggregate of approximately % of our common units. Please read "The Partnership Agreement—Limited Call Right."
Election to be treated as a corporation	If at any time our general partner determines that (i) we should no longer be characterized as a partnership but instead as an entity taxed as a corporation for U.S. federal income tax purposes or (ii) common units held by unitholders other than the general partner and its affiliates should be converted into or exchanged for interests in a newly formed entity taxed as a corporation for U.S. federal income tax purposes whose sole asset is interests in us ("parent corporation"), then our general partner may, without unitholder approval, reorganize and cause us to be treated as an entity taxable as a corporation for U.S. federal income tax purposes or cause common units held by unitholders other than the general partner and its affiliates to be converted into or exchanged for interests in the parent corporation. The general partner may take any of the foregoing actions if it in good faith determines (meaning it subjectively believes) that such action is not adverse to our best interests. In making such determination, however, our general partner is not required to take into account the immediate and long-term tax consequence to our limited partners. Please read "Risk Factors—Risk Inherent in an Investment in Us—Our general partner may elect to convert or restructure us from a partnership to an entity taxable as a corporation for U.S. federal income tax purposes without unitholder consent and without taking into account the immediately and long-term tax consequences to our limited partners" and "The Partnership Agreement—Election to be treated as a Corporation."
Eligible Holders and redemption	Units held by persons who our general partner determines are not Eligible Holders will be subject to redemption. As used herein, an Eligible Holder means any person or entity qualified to hold an interest in oil and natural gas leases on U.S. federal lands. We have the right (which we may assign to any of our affiliates), but not the obligation, to redeem all of the common units of any holder that is not an Eligible Holder or that has failed to certify or has falsely certified that such holder is an Eligible Holder. The purchase price for such redemption would be equal to the then-current market price of the common units. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. Please read "Description of the Common

	Units—Transfer Agent and Registrar—Transfer of Common Units” and “The Partnership Agreement—Non-Citizen Unitholders; Redemption.”
Estimated ratio of taxable income to distributions	We estimate that if our unitholders own the common units purchased in this offering through the record date for distributions for the period ending December 31, 2025, such unitholders will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be less than % of the cash distributed to such unitholders with respect to that period. Please read “Material U.S. Federal Income Tax Consequences—Tax Consequences of Unit Ownership—Ratio of Taxable Income to Distributions” for the basis of this estimate.
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please read “Material U.S. Federal Income Tax Consequences.”
Listing and trading symbol	We have applied to list our common units on the NYSE, subject to official notice of issuance, under the symbol “TXO.”

Summary Historical and Pro Forma Financial and Operating Data

The summary historical consolidated financial data set forth below as of and for each of the years ended December 31, 2021 and 2020 have been derived from our audited consolidated financial statements included elsewhere in this prospectus. The summary historical consolidated financial data set forth below as of March 31, 2022 and for the three months ended March 31, 2022 and 2021 are derived from our unaudited financial statements and related notes included elsewhere in this prospectus.

The summary unaudited pro forma financial data as of March 31, 2022 and for the three months ended March 31, 2022 and the year ended December 31, 2021 are derived from the unaudited pro forma condensed financial statements of TXO Energy Partners included elsewhere in this prospectus. Our unaudited pro forma condensed financial statements give pro forma effect to the following:

- the acquisition of producing properties and a gas processing plant in the Permian Basin in New Mexico and CO_2 assets in Colorado from Chevron in November 2021; and

- the issuance and sale by us to the public of common units in this offering and the application of the net proceeds as described in "Use of Proceeds."

The unaudited pro forma financial data were prepared as if the items listed above occurred on January 1, 2021, in the case of statement of operations data, or December 31, 2021, in the case of balance sheet data. We have not given pro forma effect to the Chevron Andrews Parker Acquisition or to the incremental general and administrative expenses that we expect to incur annually as a result of being a publicly traded partnership.

The unaudited pro forma historical financial data are presented for illustrative purposes only and are not necessarily indicative of the financial position that would have existed or the financial results that would have occurred if this offering and the Chevron Vacuum Acquisition had been consummated on the dates indicated, nor are they necessarily indicative of the financial position or results of our operations in the future. The pro forma adjustments, as described in the notes to the unaudited pro forma condensed combined financial statements, are preliminary and based upon currently available information and certain assumptions that our management believes are reasonable. The summary historical consolidated financial data are qualified in their entirety by, and should be read in conjunction with, the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section included in this prospectus and the consolidated financial statements and related notes and other financial information included in this prospectus. Among other things, those historical financial statements and unaudited pro forma condensed financial statements include more detailed information regarding the basis of presentation for the following information. Historical results are not necessarily indicative of results that may be expected for any future period.

You should read the following table in conjunction with "Use of Proceeds," "Management's Discussion and Analysis of Financial Condition and Results of Operations," our historical combined financial statements and our unaudited pro forma condensed financial statements and the notes thereto included elsewhere in this prospectus. Among other things, those historical financial statements and unaudited pro forma condensed financial statements include more detailed information regarding the basis of presentation for the following information.

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The following table presents non-GAAP financial measures, Adjusted EBITDAX and cash available for distribution, which we use in evaluating the financial performance of our business. These measures are not calculated or presented in accordance with generally accepted accounting principles, or GAAP. We explain these measures below and reconcile them to the most directly comparable financial measures calculated and presented in accordance with GAAP.

	TXO Energy Partners Historical				TXO Energy Partners Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31	Three Months Ended March 31,
	2021	2020	2022	2021	2021	2022
			(unaudited) (in thousands)			
Statement of Operations Data:						
Revenues:						
Oil and condensate	$ 69,971	$ 59,070	$ (2,530)	$ 10,875		
Natural gas liquids	$ 27,875	$ 8,660	$ 3,121	$ 4,777		
Natural gas	$ 130,498	$ 41,034	$ (10,129)	$ 31,975		
Total revenues[(1)]	$ 228,344	$ 108,764	$ (9,538)	$ 47,627		
Expenses:						
Production	$ 69,256	$ 49,146	$ 25,026	$ 14,316		
Exploration	$ 124	$ 55	$ 87	$ 44		
Taxes, transportation and other	$ 58,040	$ 27,509	$ 23,487	$ 12,704		
Depreciation, depletion and amortization	$ 39,889	$ 42,322	$ 9,780	$ 9,245		
Impairment	$ —	$ 134,097	$ —	$ —		
Accretion of discount on asset retirement obligations	$ 4,670	$ 3,940	$ 1,477	$ 1,320		
General and administrative	$ 12,175	$ 6,995	$ 396	$ (89)		
Total expenses	$ 184,154	$ 264,064	$ 60,253	$ 37,540		
Operating income (loss)	$ 44,190	$ (155,300)	$ (69,791)	$ 10,087		
Other income (expenses):						
Other income	$ 14,139	$ 72	$ 5,872	$ 15		
Interest income	$ 16	$ 194	$ 6	$ 3		
Interest expense	$ (5,870)	$ (8,204)	$ (1,670)	$ (1,365)		
Total other income (expenses)	$ 8,285	$ (7,938)	$ 4,208	$ (1,347)		
Net income (loss)	$ 52,475	$ (163,238)	$ (65,583)	$ 8,740		
Net income per limited partner unit (basic and diluted)						

	TXO Energy Partners Historical				TXO Energy Partners Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31	Three Months Ended March 31,
	2021	2020	2022	2021	2021	2022
			(unaudited) (in thousands)			
Weighted average number of limited partner units outstanding (basic and diluted)						
Other Financial Data:						
Adjusted EBITDAX	$ 85,348	$ 32,322	$ 38,778	$ 20,711		
Cash available for distribution	$ 72,348	$ 20,132	$ 36,499	$ 18,037		
Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 73,726	$ 18,964	$ 28,665	$ 21,859		
Investing activities	$(227,801)	$ (16,718)	$ (5,792)	$ (1,492)		
Financing activities	$ 139,689	$ 14,067	$ (15,064)	$ (20,004)		
Balance Sheet Data (at period end):						
Total assets	$ 832,820	$623,940	$840,633	$615,607		
Total long-term debt	$ 152,100	$151,252	$137,100	$131,252		
Partners' capital	$ 541,359	$303,268	$475,776	$311,660		

(1) Includes the effect of unrealized losses on commodity derivatives.

Non-GAAP Financial Measures

Adjusted EBITDAX

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

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

Cash Available for Distribution

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

Reconciliations to of Adjusted EBITDAX and cash available for distribution to GAAP Financial Measures

The following table presents our reconciliation of the non-GAAP financial measures Adjusted EBITDAX and cash available for distribution to the GAAP financial measures of net income (loss) and net cash provided by operating activities, as applicable, for each of the periods indicated.

	TXO Energy Partners Historical				TXO Energy Partners Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31	Three Months Ended March 31,
	2021	2020	2022	2021	2021	2022
	(unaudited) (in thousands)					
Net income (loss)	$52,475	$(163,238)	$ (65,583)	$ 8,740		
Interest expense	$ 5,870	$ 8,204	$ 1,670	$ 1,365		
Interest income	$ (16)	$ (194)	$ (6)	$ (3)		

	TXO Energy Partners Historical				TXO Energy Partners Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31	Three Months Ended March 31,
	2021	2020	2022	2021	2021	2022
			(unaudited) (in thousands)			
Depreciation, depletion and amortization	$39,889	$ 42,322	$ 9,780	$ 9,245		
Impairment expenses	—	$134,097	—	—		
Accretion of discount on asset retirement obligations	$ 4,670	$ 3,940	$ 1,477	$ 1,320		
Exploration expense	$ 124	$ 55	$ 87	$ 44		
Non-cash derivative (gain) / loss	$ (8,977)	$ 2,887	$91,353	—		
Non-cash incentive compensation	$ 2,400	$ 4,227	—	—		
Non-cash (gain) on forgiveness of debt	(9,152)	—	—	—		
Other non-cash (gain) / loss	$ (1,935)	$ 22	$ —	$ —		
Adjusted EBITDAX	$85,348	$ 32,322	$38,778	$ 20,711		
Net Cash Provided by Operating Activities	$73,726	$ 18,964	$28,665	$ 21,859		
Changes in operating assets and liabilities	$ 6,994	$ 6,157	$ 8,530	$ (2,399)		
Development costs[(1)]	$ (8,372)	$ (4,989)	$ (696)	$ (1,423)		
Cash Available for Distribution	$72,348	$ 20,132	$36,499	$ 18,037		

(1) Development costs includes all of our capital expenditures made for oil and gas properties, other than acquisitions.

Reconciliation of PV-10 to Standardized Measure.

Our PV-10 has historically been computed on the same basis as our standardized measure of discounted future net cash flows ("Standardized Measure"), the most comparable measure under GAAP, but does not include a provision for either future well abandonment costs or the Texas gross margin tax. PV-10 is not a financial measure calculated or presented in accordance with GAAP and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of either well abandonment costs or income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. See below for a reconciliation of the Proved Reserves PV-10 value to the Standardized Measure, the most directly comparable GAAP measure.

The following table provides a reconciliation of our Proved Reserves PV-10 value based on SEC pricing to the Standardized Measure at December 31, 2021:

		TXO Energy Partners As of December 31, 2021
(In millions)		
Proved Reserves PV-10 value	$	1,017.3
Present value of future asset retirement obligations discounted at 10%	$	(28.7)
Present value of future income taxes discounted at 10%	$	(2.0)
Standardized Measure	$	986.6

Summary of Reserve, Production and Operating Data

The following tables summarize our estimated oil, natural gas and NGL reserves as of December 31, 2021 and our production and historical operating data for the year ended December 31, 2021 on a historical basis and on a pro forma basis giving effect to the Chevron Vacuum Acquisition as if it had occurred on January 1, 2021. The information included in these tables is based on reserve reports prepared by our independent consulting petroleum engineers, Cawley, Gillespie & Associates, Inc. For more information regarding our reserve volumes and values, see “Business and Properties—Oil, Natural Gas and NGL Data—Reserves” and Appendix C. Historical reserve volumes and values are not necessarily indicative of results that may be expected for any future period.

Summary of Reserves as of December 31, 2021 Based on SEC Pricing

Our historical SEC reserves, PV-10 and Standardized Measure were calculated using oil and gas price parameters established by current SEC guidelines, including the use of an average effective price, calculated as prices equal to the 12-month unweighted arithmetic average of the first day of the month prices for each of the preceding 12 months as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions (“SEC Pricing”). These prices were adjusted for differentials on a per-property basis, which may include local basis differential, treating cost, transportation, gas shrinkage, gas heating value and/or crude quality and gravity corrections. All prices are held constant throughout the lives of the properties.

		TXO Energy Partners As of December 31, 2021(1)
Proved Developed:		
Oil (MBbls)		30,207.9
Natural gas (MMcf)		353,214.9
Natural gas liquid (MBbls)		17,434.2
Oil equivalent (MBoe)		106,511.3
PV-10 (in millions)(2)	$	772.2
Proved Undeveloped:		
Oil (MBbls)		18,362.9
Natural gas (MMcf)		26,061.0
Natural gas liquid (MBbls)		590.3
Oil equivalent (MBoe)		23,296.6
PV-10 (in millions)(2)	$	245.1
Total Proved:		
Oil (MBbls)		48,570.8
Natural gas (MMcf)		379,275.9
Natural gas liquid (MBbls)		18,024.5
Oil equivalent (MBoe)		129,807.9
Standardized Measure (in millions)(2)	$	986.6
PV-10 (in millions)(2)	$	1,017.3

(1) Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC regulations. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $66.56 per barrel for oil and $3.60 per MMBTU for natural gas at December 31, 2021. The base prices were based upon Henry Hub and WTI-Cushing spot prices, respectively. These base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these net adjustments, the net realized prices for the SEC price case over the life of the proved properties was estimated to be $64.76 per barrel for oil, $19.62 per barrel for NGLs and $2.31 per Mcf for natural gas for the year ended December 31, 2021.

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions.

Summary of Reserves as of December 31, 2021 Based on NYMEX Pricing

The following table presents our estimated net proved oil, natural gas and NGL reserves as of December 31, 2021 using average annual NYMEX forward-month contract pricing in effect as of June 15, 2022 (“NYMEX Pricing”) but is otherwise presented on the same basis as the reserve information prepared in accordance with SEC regulations. We believe that the use of NYMEX forward-month prices provides investors with additional useful information about our reserves, as the NYMEX forward-month prices are based on a market-based expectation of oil and natural gas prices as of a certain date. NYMEX forward-month prices are not necessarily a projection of future oil and natural gas prices. Investors should consider NYMEX forward-month prices in addition to, and not as a substitute for, SEC prices, when considering our reserves of oil, natural gas and NGLs.

		TXO Energy Partners As of December 31, 2021(1)
Proved Developed:		
Oil (MBbls)		30,853.6
Natural gas (MMcf)		386,809.7
Natural gas liquid (MBbls)		18,739.9
Oil equivalent (MBoe)		114,061.8
PV-10 (in millions)(2)	$	1,233.8
Proved Undeveloped:		
Oil (MBbls)		18,415.4
Natural gas (MMcf)		26,082.1
Natural gas liquid (MBbls)		594.9
Oil equivalent (MBoe)		23,357.3
PV-10 (in millions)(2)	$	310.8
Total Proved:		
Oil (MBbls)		49,269.0
Natural gas (MMcf)		412,891.8
Natural gas liquid (MBbls)		19,334.8
Oil equivalent (MBoe)		137,419.1
PV-10 (in millions)(2)	$	1,544.6

(1) The NYMEX futures prices as of June 15, 2022 used to prepare our reserve report are shown in the following table. These base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these net adjustments, the net realized prices for the NYMEX futures price case over the life of the proved properties was estimated to be $73.63 per barrel for oil, $21.47 per barrel for NGLs and $3.63 per Mcf for natural gas.

	2022	2023	2024	2025	2026	Thereafter
Natural gas price (per MMBtu)	$ 7.35	$ 6.12	$ 5.19	$ 4.87	$ 4.78	$ 4.78
Oil price (per Bbl)	$ 107.49	$ 94.37	$ 84.30	$ 76.80	$ 71.42	$ 71.42

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Our PV-10 has historically been computed on the same basis as our Standardized Measure, the most comparable measure under GAAP, but does not include a provision for either future well abandonment costs or the Texas gross margin tax. PV-10 is not a financial measure calculated or presented in accordance with GAAP and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of either well abandonment costs or income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

Select Production and Operating Statistics

The following table summarizes our oil, natural gas and NGL production and historical operating data for the periods presented on both a historical basis and on a pro forma basis giving effect to the Chevron Vacuum Acquisition.

	TXO Energy Partners Historical		TXO Energy Partners Pro Forma	
	Year Ended December 31, 2021	**Three Months Ended March 31, 2022**	**Year Ended December 31, 2021**	**Three Months Ended March 31, 2022**
Net Production Volumes:				
Oil (MBbl)	1,033	517		
Natural Gas (MMcf)	30,590	7,550		
NGLs (MBbl)	1,089	302		
Total (MBoe)	7,220	2,077		
Average daily production (MBoe per day)	20	23		
Average Wellhead Realized Prices (before giving effect to derivatives):				
Oil ($/Bbl)	$ 67.41	$ 93.62		
Natural Gas ($/Mcf)	$ 4.00	$ 4.90		
NGLs ($/Bbl)	$ 25.16	$ 38.30		
Average Wellhead Realized Prices (after giving effect to derivatives):				
Oil ($/Bbl)	$ 67.74	$ (4.89)		
Natural Gas ($/Mcf)	$ 4.27	$ (1.34)		
NGLs ($/Bbl)	$ 25.60	$ 10.35		
Operating costs and expenses (per Boe):				
Production	$ 9.59	$ 12.05		
Taxes, transportation, and other	$ 8.04	$ 11.31		
Depreciation, depletion, amortization and accretion	$ 5.52	$ 4.71		
General and administrative expenses	$ 1.69	$ 0.19		

RISK FACTORS

Investing in our common units involves a high degree of risk. You should carefully consider the risks described below with all of the other information included in this prospectus before deciding to invest in our common units. Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. Additionally, new risks may emerge at any time and we cannot predict those risks or estimate the extent to which they may affect financial performance

If any of the following risks actually occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay distributions on our common units, the trading price of our common units could decline and our unitholders could lose all or part of their investment.

Risks Related to Cash Distributions

We may not have sufficient available cash to pay any quarterly distribution on our common units following the establishment of cash reserves and payment of expenses.

We may not have sufficient available cash each quarter to pay distributions on our common units. Under the terms of our partnership agreement, the amount of cash available for distribution will be reduced by our operating expenses and the amount of any cash reserves established by our general partner to provide for future operations, future capital expenditures, including development, optimization and exploitation of our oil and natural gas properties, future debt service requirements and future cash distributions to our unitholders. The amount of cash that we distribute to our unitholders will depend principally on the cash we generate from operations, which will depend on, among other factors:

- the amount of oil, natural gas and NGLs we produce;
- the prices at which we sell our oil, natural gas and NGL production;
- the amount and timing of settlements on our commodity derivative contracts;
- the level of our capital expenditures, including scheduled and unexpected maintenance expenditures;
- the level of our operating costs, including payments to our general partner and its affiliates for general and administrative expenses; and
- the level of our interest expenses, which will depend on the amount of our outstanding indebtedness and the applicable interest rate.

Furthermore, the amount of cash we have available for distribution depends primarily on our cash flow, including cash from financial reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net income for financial accounting purposes.

The assumptions underlying the forecast of cash available for distribution we include in "Our Cash Distribution Policy and Restrictions on Distributions" may prove inaccurate and are subject to significant risks and uncertainties that could cause actual results to differ materially from our forecasted results.

Our management's forecast of cash available for distribution set forth in "Our Cash Distribution Policy and Restrictions on Distributions" includes our forecasted results of operations, Adjusted EBITDA and cash available for distribution for the twelve months ending June 30, 2023. The assumptions underlying the forecast may prove inaccurate and are subject to significant risks and uncertainties that could cause actual results to differ materially from those forecasted. If our actual results are significantly below forecasted results, or if our expenses are greater than forecasted, we may not be able to pay the forecasted annual distribution or any amount on our common units, which may cause the market price of our common units to decline materially.

The amount of our quarterly cash distributions from our available cash, if any, may vary significantly both quarterly and annually and will be directly dependent on the performance of our business. We will not have a minimum quarterly distribution and could pay no distribution with respect to any particular quarter.

Investors who are looking for an investment that will pay regular and predictable quarterly distributions should not invest in our common units. Our future business performance may be volatile, and our cash flows may be unstable. We will not have a minimum quarterly distribution. Because our quarterly distributions will significantly correlate to the cash we generate each quarter after payment of our fixed and variable expenses, future quarterly distributions paid to our unitholders will vary significantly from quarter to quarter and may be zero. Please read "Cash Distribution Policy and Restrictions on Distributions."

Risks Related to Our Business and the Oil, Natural Gas and NGL Industry

The volatility of oil, natural gas and NGL prices due to factors beyond our control greatly affects our financial condition, results of operations and cash available for distribution.

Our revenues, operating results, cash available for distribution and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil, natural gas and NGLs. Prices for oil, natural gas and NGLs are subject to wide fluctuations in response to relatively minor changes in supply and demand, market uncertainty and a variety of additional factors beyond our control. These factors include, but are not limited to:

- worldwide and regional economic conditions impacting the supply and demand for oil, natural gas and NGLs;
- the level of global oil and natural gas exploration and production;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, the armed conflict in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;

- the ability of and actions taken by members of Organization of the Petroleum Exporting Countries ("OPEC") and otheroil-producing nations in connection with their arrangements to maintain oil prices and production controls;
- the impact on worldwide economic activity of an epidemic, outbreak or other public health events, such asCOVID-19;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions across the globe;
- technological advances affecting energy consumption and energy supply;
- speculative trading in commodity markets, including expectations about future commodity prices;
- the proximity of our natural gas, NGL and oil production to, and capacity and cost of, natural gas pipelines and other transportation and storage facilities, and other factors that result in differentials to benchmark prices;
- the impact of energy conservation efforts;
- the price and availability of alternative fuels;
- stockholder activism or activities by non-governmental organizations to restrict the exploration, development and production of oil and natural gas to minimize the emission of greenhouse gases;
- domestic, local and foreign governmental regulation and taxes; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements accurately. Changes in oil, natural gas and NGL prices have a significant impact on the amount of oil, natural gas and NGL that we can produce economically, the value of our reserves and on our cash flows. Historically, oil, natural gas and NGL prices and markets have been volatile, and those prices and markets are likely to continue to be volatile in the future. In particular, oil prices fluctuated during 2018 and 2019, and declined dramatically during 2020 due to demand collapse caused by COVID-10 and associated lockdowns, dropping to ($37.63) per barrel of crude WTI oil on April 20, 2020. During the year ended December 31, 2021, the NYMEX daily oil price reached a high of $84.65 per Bbl in October 2021 and experienced a low of $47.62 in January 2021, and the NYMEX daily natural gas price reached a high of $23.86 per MMBtu in February 2021 and experienced a low of $2.43 in April 2021, and prices have remained volatile. In response to the conflict in Ukraine, the NYMEX daily oil price reached a high of $123.70 on March 8, 2022, and the NYMEX daily natural gas price reached a high of $9.44 on May 25, 2022. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our financial condition, results of operations and cash available for distribution.

Unless we replace the reserves we produce, our revenues and production will decline, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders.

We may be unable to pay quarterly distributions to our unitholders without substantial capital expenditures that maintain our asset base. Producing oil and natural gas reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future reserves and production and, therefore, our cash flow and ability to make distributions are highly dependent on our success in efficiently developing, optimizing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production on economically acceptable terms, which would adversely affect our business, financial condition and results of operations and reduce cash available for distribution to our unitholders.

If commodity prices decline and remain depressed for a prolonged period, production from a significant portion of our properties may become uneconomic and cause downward adjustments of our reserve estimates and write downs of the value of such properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

Significantly lower commodity prices over extended periods of time may render many of our development projects uneconomic and result in a downward adjustment of our reserve estimates, which would negatively impact our borrowing base and ability to borrow to fund our operations or make distributions to our unitholders. As a result, we may reduce the amount of distributions paid to our unitholders or cease paying distributions. In addition, a significant or sustained decline in commodity prices could hinder our ability to effectively execute our hedging strategy. For example, during a period of declining commodity prices, we may enter into commodity derivative contracts at relatively unattractive prices in order to mitigate a potential decrease in our borrowing base upon a redetermination.

Furthermore, as a result of a lower net commodity price environment for some of our oil and natural gas assets, in 2020 we recorded an impairment of $133.2 million for certain of our long-lived assets in the New Mexico Permian Basin, $0.2 million for our assets in East Texas and $0.7 million on our unproved properties primarily in the Texas Permian Basin. Prior to 2020, our historical impairment of proved properties included $177.4 million of proved property impairments from 2014 through 2018. Due to the improvement in commodity pricing environment and industry conditions, we did not record any impairments in 2021. However, if commodity prices fall below certain levels, our production, proved reserves and cash flows will be adversely impacted and we may be required to record additional impairments , which could be material. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our Credit Facility, which may be determined at the discretion of our lenders. See "—Any significant reduction in the borrowing base under our Credit Facility as a result of periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations."

Currently our producing properties are concentrated in the Permian and San Juan Basins, making us vulnerable to risks associated with operating in a limited number of geographic areas.

As a result of our geographic concentration, adverse industry developments in our operating areas could have a greater impact on our financial condition and results of operations than if we were more geographically diverse. We may also be disproportionately exposed to the impact of regional supply and demand factors, governmental regulations or midstream capacity constraints. Delays or interruptions caused by such adverse developments could have a material adverse effect on our financial condition and results of operations.

Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field wide rules, which could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has been the case recently in our operating areas, we are subject to increasing competition for drilling rigs, workover rigs, tubulars and other well equipment, services, supplies as well as increased labor costs and qualified personnel, which may lead to periodic shortages or delays. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

Drilling for and producing oil, natural gas and NGLs are high-risk activities with many uncertainties that could adversely affect our business, financial condition, results of operations and cash distributions to unitholders.

Our future financial condition and results of operations, and therefore our ability to make cash distributions to our unitholders, will depend on the success of our acquisition, development, optimization and exploitation activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable production.

Our decisions to purchase, develop, optimize or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Reserve estimates depend on many assumptions that may ultimately be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- unexpected or adverse drilling conditions;
- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements including permitting requirements, limitations on or resulting from wastewater discharge and the disposal of exploration and production wastes, including subsurface injections;
- elevated pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;

- adverse weather conditions, such as hurricanes, lightning storms, flooding, tornadoes, snow or ice storms and changes in weather patterns;
- issues related to compliance with, or changes in, environmental and other governmental regulations;
- environmental hazards, such as oil and natural gas leaks, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil, natural gas and NGL prices;
- the availability and timely issuance of required governmental permits and licenses; and
- title defects or legal disputes regarding leasehold rights.

We may be unable to make accretive acquisitions or successfully integrate acquired businesses or assets, and any inability to do so may disrupt our business and hinder our growth potential.

Our ability to grow and to increase distributions to our unitholders depends in part on our ability to make acquisitions that result in an increase in cash available for distribution. There is intense competition for acquisition opportunities in our industry and we may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition, do so on commercially acceptable terms or obtain sufficient financing to do so. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions.

In addition, our debt arrangements impose certain limitations on our ability to enter into mergers or combination transactions and to make certain investments. Our debt arrangements also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement."

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. Our failure to achieve consolidation savings, to successfully integrate the acquired businesses and assets into our existing operations or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential liabilities, including, but not limited to, environmental liabilities. Such assessments are inexact and inherently uncertain. For these reasons, the properties we have acquired or may acquire in the future may not produce as projected. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not review every well, pipeline or associated facility. We cannot necessarily observe structural and environmental problems, such as pipe corrosion or groundwater contamination, when a review is performed. We may be unable to obtain contractual indemnities from any seller for liabilities arising from or attributable to the period prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Increased costs of capital could adversely affect our business.

Our business could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. For example, since March 2022, the Federal Reserve has raised its target range for the federal funds rate twice, including by 50 basis points in May 2022 and by 75 basis points in June 2022. Furthermore, additional rate hikes are likely to occur for the foreseeable future, as indicated by the minutes of the Federal Open Markets Committee. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our activities. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our business strategy and cash flows.

Drilling locations that we decide to drill may not yield oil, natural gas or NGLs in commercially viable quantities

We may in the future explore potential drilling locations in areas where we currently own properties and in other areas. These potential drilling locations would be in various stages of evaluation, ranging from a location that is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively, prior to drilling, whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil, natural gas or NGLs exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our other identified drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. The cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Because of these uncertain factors, we do not know if the potential well locations we have identified, or will identify, will ever be drilled or if we will be able to produce oil, natural gas and NGLs from these or any other potential locations. As such, our actual drilling activities may materially differ from those presently identified.

Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease or other interest in a specific mineral interest. The existence of a material title deficiency can render a lease or other interest worthless and can adversely affect our results of operations and financial condition. The failure of title on a lease, in a unit or any other mineral interest may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We operate certain of our properties through a joint venture over which we have shared control.

We conduct certain of our operations through Cross Timbers, a joint venture owned 50% by us and 50% by certain affiliates of Exxon and XTO, which we refer to collectively as the "XTO Entities." For the year ended December 31, 2021, our interest in Cross Timbers represented approximately 41% of our revenues and approximately 35% of our proved reserves.

In accordance with the limited liability company agreement governing Cross Timbers, or the "JV LLCA", Cross Timbers is managed by us and governed by a member management committee comprised of six members, three of whom are appointed by us and three of whom are appointed by the XTO Entities. The JV LLCA requires that certain matters, including certain material contracts or acquisitions, mergers, sale of substantially all assets or other change of control transactions, and transfers of our interest to a third party, be approved by unanimous consent of the voting members of the management committee and therefore such actions require the approval of the XTO Entities. Our ability to make distributions to our unitholders depends in part on the performance of this entity and its ability to distribute funds to us. We face certain risks associated with shared control, and the XTO Entities may at any time have economic, business or legal interests or goals that are inconsistent with ours.

We own non-operating interests in properties developed and operated by third parties and some of our leasehold acreage could be pooled by a third-party operator. As a result, we are unable, or may become unable as a result of pooling, to control the operation and profitability of such properties.

We participate in the drilling and completion of wells with third-party operators that exercise exclusive control over such operations. As a participant, we rely on the third-party operators to successfully operate these properties pursuant to joint operating agreements and other contractual arrangements. Similarly, our acreage in Colorado, Texas and New Mexico may be pooled by third-party operators under state law. If our acreage is involuntarily pooled under state forced pooling statutes, it would reduce our control over such acreage and we could lose operatorship over a portion of our acreage that we plan to develop.

We may not be able to maximize the value associated with acreage that we own but do not operate in the manner we believe appropriate, or at all. We cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third-party operator, including such operator's determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third-party operator's operational expertise and financial resources and its ability to gain the approval of other participants in drilling wells will impact the timing and potential success of drilling and development activities in a manner that we are unable to control. A third-party operator's failure to adequately perform operations, breach of the applicable agreements or failure to act in ways that are favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our financial condition and results of operations.

Extreme weather conditions could adversely affect our ability to conduct drilling activities in the areas where we operate.

There has been public discussion that climate change may be associated with more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, which could affect some, or all, of our operations. Our development, optimization and exploitation activities and equipment could be adversely affected by extreme weather conditions, such as hurricanes, thunderstorms, tornadoes and snow or ice storms, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. Such extreme weather conditions could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

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

Concerns over global economic conditions, energy costs, supply chain disruptions, increased demand, labor shortages associated with a fully employed U.S. labor force, geopolitical issues, inflation, the availability and cost of credit and the United States financial market and other factors have contributed to increased economic uncertainty and diminished expectations for the global economy. Though we incorporated inflationary factors into our 2022 business plan, inflation has outpaced those original assumptions. Although inflation in the United States had been relatively low for many years, there was a significant increase in inflation beginning in the second half of 2021, which has continued into 2022, due to a substantial increase in money supply, a stimulative fiscal policy, a significant rebound in consumer demand as COVID-19 restrictions were relaxed, the Russia-Ukraine war and worldwide supply chain disruptions resulting from the economic contraction caused by COVID-19 and lockdowns followed by a rapid recovery. Inflation rose from 5.4% in June 2021 to 5.8% in December 2021 to 8.6% in May 2022. We continue to undertake actions and implement plans to strengthen our supply chain to address these pressures and protect the requisite access to commodities and services. Nevertheless, we expect for the foreseeable future to experience supply chain constraints and inflationary pressure on our cost structure. These supply chain constraints and inflationary pressures will likely continue to adversely impact our operating costs and if we are unable to manage our supply chain, it may impact our ability to procure materials and equipment in a timely and cost-effective manner, if at all, which could impact our ability to distribute available cash and result in reduced margins and production delays and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

In addition, continued hostilities related to the Russian invasion of Ukraine and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors and other factors, such as another surge in COVID-19 cases or decreased demand from China, combined with volatile commodity prices, and declining business and consumer confidence may contribute to an economic slowdown and a recession. Recent growing concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, or the threat thereof, could have a material adverse effect on our business, liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units.

We face risks related to epidemics, outbreaks or other public health events, or the threat thereof, that are outside of our control, and could significantly disrupt our business and operational plans and adversely affect our liquidity, financial condition, results of operations, cash flows and ability to pay distributions on our common units. The COVID-19 pandemic has adversely affected the global economy and has resulted in unprecedented governmental actions in the United States and countries around the world, including, among other things, social distancing guidelines, travel restrictions and stay-at-home orders, among other actions, which caused a significant decrease in activity in the global economy and the demand for oil, and to a lesser extent, natural gas and NGLs. Additionally, the effects of the COVID-19 pandemic might worsen the likelihood or the impact of other risks already inherent in our business. We believe that the known and potential impacts of the COVID-19 pandemic and related events include, but are not limited to, the following:

- disruption in the demand for natural gas and other petroleum products;
- intentional project delays until commodity prices stabilize;
- potentially higher borrowing costs in the future;
- a need to preserve liquidity, which could result in a reductions, delays or changes in our capital expenditures;
- liabilities resulting from operational delays due to decreased productivity resulting from stay-at-home orders affecting our workforce or facility closures resulting from the COVID-19 pandemic;
- future asset impairments, including impairment of our natural gas properties and other property and equipment; and
- infections and quarantining of our employees and the personnel of vendors, suppliers and other third parties.

New variants of the virus could cause further commodity market volatility and resulting financial market instability, or any other event described above, and these are variables beyond our control that may adversely impact our operating cash flows, our ability to pay distributions on our common stock and our ability to access the capital markets.

We use derivative instruments to economically hedge exposure to changes in commodity price and, as a result, are exposed to credit risk and market risk.

We periodically enter into futures contracts, energy swaps, options, collars and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas and natural gas liquids sales See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Derivatives.” By using derivative instruments to economically hedge exposure to changes in commodity prices, we could limit the benefit we would receive from increases in the prices for oil and natural gas, which could have an adverse effect on our financial condition. Likewise, to the extent our production is not hedged, we are exposed to declines in commodity prices, and our derivative arrangements may be inadequate to protect us from continuing and prolonged declines in commodity prices.

Changes in the fair value of commodity price derivatives are recognized currently in earnings. Realized and unrealized gains and losses on commodity derivatives are recognized in oil, NGL and natural gas revenues. Settlements of derivatives are included in cash flows from operating activities. While our price risk management activities decrease the volatility of cash flows, they may obscure our reported financial condition. As required under GAAP, we record derivative financial instruments at their fair value, representing projected gains and losses to be realized upon settlement of these contracts in subsequent periods when related production occurs. These gains and losses are generally offset by increases and decreases in the market value of our proved reserves, which are not reflected in the financial statements. For example, for the three months ended March 31, 2022, revenues decreased $57.2 million to ($9.5) million from $47.6 million for the three months ended March 31, 2021, and the decrease was primarily attributable to losses on our hedging activity of $106.5 million, of which $91.3 million were unrealized losses and $15.2 million were realized losses.

Additionally, our Credit Facility may hinder our ability to effectively execute our hedging strategy. We are allowed to hedge at most 90% of reasonably anticipated projected production, but we are required to hedge at least (a) 75% of reasonably anticipated projected production of proved developed producing reserves for the 12-month period following January 1, 2022 and (b) thereafter 50% of reasonably anticipated projected production of proved developed producing reserves for the 30-month period following the date of any hedging transaction. However, as of any time, if the net leverage ratio (the ratio of total net debt-to-EBITDAX) is less than or equal to 1.0 to 1.0 and the cash and cash equivalents on hand are equal to or greater than 20% of the borrowing base then in effect, the minimum required hedge volume for month one through month 24 will be reduced to 50%. See “—Our Credit Facility has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement.”

We also expose ourselves to credit risk due to the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. Disruptions in the financial markets could lead to sudden decreases in a counterparty’s liquidity, which could make it unable to perform under the terms of the contract and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty’s creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

Reserve estimates depend on many assumptions that may ultimately be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil, natural gas and NGL reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

Furthermore, SEC rules require that, subject to limited exceptions, PUD reserves may only be recorded if they relate to wells scheduled to be drilled within five years after the date of booking. This rule may limit our potential to record additional PUD reserves as we pursue our drilling program. To the extent that natural gas and oil prices become depressed or decline materially from current levels, such condition could render uneconomic a number of our identified drilling locations, and we may be required to write down our PUD reserves if we do not drill those wells within the required five-year time frame. If we choose not to develop PUD reserves, or if we are not otherwise able to successfully develop them, then we will be required to remove the associated volumes from our reported proved reserves.

The preparation of reserve estimates requires the projection of production rates and the timing of development expenditures based on an analysis of available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may revise reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

The standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved reserves.

The present value of future net cash flow from our proved reserves, or standardized measure, may not represent the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on the 12-month average oil and natural gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. For example, our estimated proved reserves as of December 31, 2021 were calculated under SEC rules using the unweighted arithmetic average first day of the month prices for the prior 12 months of $3.60/MMBtu for natural gas and $66.56/Bbl for oil at December 31, 2021, which for certain periods during this period were substantially different from the available spot prices. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with Accounting Standards Codification 932, "*Extractive Activities—Oil and Gas*," may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

We depend upon several significant purchasers for the sale of most of our oil, natural gas and NGL production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

For the year ended December 31, 2021, Phillips 66 Company, Tenaska Marketing andEco-Energy, Inc. accounted for more than 40% of our total revenues, excluding the impact of our commodity derivatives. For the year ended December 31, 2020, Phillips 66 Company and Tenaska Marketing accounted for more than 40% of our total revenues, excluding the impact of our commodity derivatives. No other purchaser accounted for more than 10% of our revenue during such periods. We do not have long-term contracts with our customers but rather we sell the substantial majority of our production under arm's length contracts with terms of 12 months or less, including on a month-to-month basis, to a relatively small number of customers. The loss of any one of these purchasers, the inability or failure of our significant purchasers to meet their obligations to us or their insolvency or liquidation could materially adversely affect our financial condition, results of operations and ability to make distributions to our unitholders. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have ready access to suitable markets for our future production. See "Business and Properties—Operations—Marketing and Customers."

The availability of a ready market for any hydrocarbons we produce depends on numerous factors beyond our control, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of natural gas and NGL pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil, natural gas and NGL production and federal regulation of oil, natural gas and NGLs sold in interstate commerce.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The oil and natural gas industry is intensely competitive, and we compete with companies that possess and employ financial, technical and personnel resources substantially greater than ours. Our ability to acquire additional properties and to exploit reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Any inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations and our ability to make distributions to our unitholders.

Our Credit Facility has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders.

Our Credit Facility restricts, among other things our ability to:

- incur certain liens or permit them to exist;

- merge or consolidate with another company;

- incur or guarantee additional debt;
- make certain investments and acquisitions;
- make or pay distributions on, or redeem or repurchase, common units, if an event of default or borrowing base deficiency exists;
- enter into certain types of transactions with affiliates; and
- transfer, sell or otherwise dispose of assets.

In addition, our Credit Facility will require us to comply with customary financial covenants and specified financial ratios, including that we 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 3.00 to 1.00. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any provisions of our Credit Facility that are not cured or waived within specific time periods, our lender may declare our indebtedness thereunder to be immediately due and payable, our ability to make distributions to our unitholders will be inhibited and our lenders' commitment to make further loans to us may terminate. Any such acceleration of such debt could also result in a cross-acceleration of other future indebtedness which we may incur. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our Credit Facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our Credit Facility, the lenders could seek to foreclose on our assets or force us to seek bankruptcy protection.

In addition, our Credit Facility may hinder our ability to effectively execute our hedging strategy. Our Credit Facility limits the maximum percentage of our production that we can hedge and the duration of those hedges, so we may be unable to enter into additional commodity derivative contracts during favorable market conditions and, thus, unable to lock in attractive future prices for our product sales. Conversely, our Credit Facility also requires us to hedge a minimum percentage of our production, which may cause us to enter into commodity derivative contracts at inopportune times. For example, during a period of declining commodity prices, we may enter into commodity derivative contracts at relatively unattractive prices in order to mitigate a potential decrease in our borrowing base upon a redetermination.

Any significant reduction in the borrowing base under our Credit Facility as a result of periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Our Credit Facility limits the amount we can borrow up to a borrowing base amount. The administrative agent under our Credit Facility determines our borrowing base based on the value of our oil and natural gas properties. The borrowing base is subject to further adjustments for asset dispositions, material title deficiencies, certain terminations of hedge agreements and issuances of permitted additional indebtedness. As of June 8, 2022, the last date of redetermination, our borrowing base was $165 million. Such amount will be redetermined semi-annually on or before each March 15 and September 1 and will depend on the volumes of our proved oil and natural gas reserves and estimated cash flows from these reserves and other information deemed relevant by the administrative agent under the Credit Facility, including our business, financial condition and debt obligations, the types of reserves, the value and effect of hedge contracts then in effect and the effect of gas imbalances. In addition, our lenders will have flexibility to reduce our borrowing base due to subjective factors.

In the future, we may not be able to access adequate funding under our Credit Facility (or a replacement facility) as a result of a decrease in the borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of our lenders to meet their funding obligations. Declines in commodity prices could result in a determination by the lenders to decrease the borrowing base in the future and, in such a case, we could be required to promptly repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our respective drilling and development plan, make acquisitions or otherwise carry out business plans, which could have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our debt arrangements, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our Credit Facility, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. If oil, natural gas and NGL prices decline for an extended period of time, we may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional equity or debt capital or restructure or refinance indebtedness or seek bankruptcy protection to facilitate a restructuring. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt or preferred equity arrangements may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our Credit Facility currently restricts our ability to dispose of assets and our use of the proceeds from such disposition in certain circumstances. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

Our level of indebtedness may increase and reduce our financial flexibility.

Although we do not expect to have any indebtedness at the closing of this offering, we may incur significant indebtedness whether through future debt issuances or by drawing down on the $165 million of availability under our Credit Facility in the future in order to make acquisitions or to develop our properties or for other general corporate purposes. Such indebtedness could affect our operations in several ways:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;

- the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay distributions on our common units and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and our industry;
- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a significant portion of our then-outstanding bank borrowings; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness, if incurred in the future, increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness in such event depends on our future performance. General economic conditions, commodity prices, and financial, business, and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt and future working capital, borrowings, or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our common units or a refinancing of our debt include financial market conditions (including any financial crisis), the value of our assets, and our performance at the time we need capital.

Our drilling and production programs may not be able to obtain access to truck transportation, pipelines and storage facilities, natural gas gathering facilities, and other transportation, processing and refining facilities to market our oil, natural gas and NGL production, and our initiatives to expand our access to midstream and operational infrastructure may be unsuccessful.

The marketing of oil, natural gas and NGL production depends in large part on the capacity and availability of trucks, pipelines and storage facilities, natural gas gathering systems and other transportation, processing and refining facilities. In order to market new or increased production, new facilities or expanded capacity on existing facilities may be required. Access to transportation, processing, and refining facilities, whether new or existing, is, in many respects, beyond our control. If these facilities are unavailable to us because we are unable to obtain service on commercially reasonable terms, the owners and operators of such facilities are unable to obtain permits for new or expanded capacity in compliance with environmental and other governmental or regulatory requirements or are delayed in obtaining such permits, or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit and sell our oil, natural gas and NGL production.

Increases in activity in our operating areas could, in the future, contribute to bottlenecks in processing and transportation that could negatively affect our results of operations, and these adverse effects could be disproportionately severe to us compared to our more geographically diverse competitors. As a result, our business, financial condition and results of operations could be adversely affected.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flows and ability to complete development activities as planned.

Historically, our capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for experienced development crews and oil field equipment and services and materials as drilling activity increases; and increased taxes, which could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues and reduce our cash available for distribution to our unitholders. Decreased levels of drilling activity in the oil and natural gas industry in recent periods have led to declining costs of some drilling equipment, materials and supplies. However, such costs may rise faster than increases in our revenue if commodity prices rise, thereby negatively impacting our profitability, cash flows and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

We are highly dependent on the services of our senior management and the loss of senior management or technical personnel could adversely affect our operations.

We depend on the services of our senior management and technical personnel. Our management team has an average of 34 years' experience in the oil and gas industry. There can be no assurance that we would be able to replace such members of management with comparable replacements or that such replacements would integrate well with our existing team. Further, the loss of the services of our senior management could have a material adverse effect on our business, financial condition and results of operations. In particular, the loss of the services of one or more members of our management team could disrupt our operations. We do not maintain, nor do we plan to obtain, "key person" life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees. Our continued success will depend, in part, on our ability to attract and retain experienced technical personnel, including geologists, engineers and other professionals. Competition for these professionals is strong and will likely intensify as a significant portion of today's engineers, geologists and other professionals working within the oil and natural gas industry will reach the age of retirement in the coming years. We are likely to continue to experience increased costs to attract and retain these professionals.

Large numbers of technical personnel in the oil and gas industry are approaching the normal retirement age of 65 or have otherwise accepted an early retirement during the COVID-19 pandemic. These and other factors may lead to a shortage of qualified, entry-level technical personnel and increased compensation costs. The foregoing factors may lead to additional competition from oil and gas companies attempting to meet their hiring needs. If a shortage of technical personnel materializes, companies in the oil and gas industry may be unable to hire adequate numbers of technical personnel to meet their needs, resulting in disruptions, increased costs of operations, financial difficulties and other adverse effects, and these circumstances may become more severe in the future and thereby cause a material adverse effect on our business.

We are responsible for the decommissioning, abandonment, and reclamation costs for our facilities, which could decrease funds available for servicing our debt obligations and other operating expenses.

We are responsible for compliance with all applicable laws and regulations regarding the decommissioning, abandonment and reclamation of our facilities at the end of their economic life, the costs of which may be substantial. It is not possible to predict these costs with certainty since they will be a function of regulatory requirements at the time of decommissioning, abandonment and reclamation. We may, in the future, determine it prudent or be required by applicable laws or regulations to establish and fund one or more decommissioning, abandonment and reclamation reserve funds to provide for payment of future decommissioning, abandonment and reclamation costs, which could decrease funds available to service debt obligations. In addition, such reserves, if established, may not be sufficient to satisfy such future decommissioning, abandonment and reclamation costs and we will be responsible for the payment of the balance of such costs.

Asset retirement obligations for our oil and gas assets and properties are estimates, and actual costs could vary significantly.

We are required to record a liability for the discounted present value of our estimated asset retirement obligations to plug and abandon inactive wells and related assets and non-producing oil and gas properties in which we have a working interest. Such asset retirement obligations may include complete structural removal and/or restoration of the land. At December 31, 2021, we had accrued asset retirement obligations of $104.5 million. Although management has used its best efforts to determine future asset retirement obligations, assumptions and estimates can be influenced by many factors beyond management’s control, including, but not limited to, changes in regulatory requirements, which may be more restrictive in the future, changes in costs for abandonment related services and technologies, which could increase or decrease based on supply and demand, and/or extreme weather conditions, such as hurricanes and lightning storms, which may cause structural or other damage to oil and natural gas assets and properties. Accordingly, our estimate of future asset retirement obligations could differ materially from actual costs that may be incurred.

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

As an oil, natural gas and NGL producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, phishing, ransomware, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability. Although we maintain insurance to protect against losses resulting from certain data protection breaches and cyber-attacks, our coverage for protecting against such risks may not be sufficient.

In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period, and our systems and insurance coverage for protecting against such cybersecurity risks may be costly and may not be sufficient. As cyber-attackers become more sophisticated, we may be required to expend significant additional resources to continue to protect our business or remediate the damage from cyber-attacks. Furthermore, the continuing and evolving threat of cyber-attacks has resulted in increased regulatory focus on prevention, and we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. To the extent we face increased regulatory requirements, we may be required to expend significant additional resources to meet such requirements.

We are subject to a number of privacy and data protection laws, rules and directives (collectively, data protection laws) relating to the processing of personal data.

The regulatory environment surrounding data protection laws is uncertain. Complying with varying jurisdictional requirements could increase the costs and complexity of compliance, and violations of applicable data protection laws can result in significant penalties. A determination that there have been violations of applicable data protection laws could expose us to significant damage awards, fines and other penalties that could materially harm our business and reputation.

Any failure, or perceived failure, by us to comply with applicable data protection laws could result in proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments and negative publicity, require us to change our business practices, increase the costs and complexity of compliance and adversely affect our business. As noted above, we are also subject to the possibility of security and privacy breaches, which themselves may result in a violation of these laws. Additionally, the acquisition of a company that is not in compliance with applicable data protection laws may result in a violation of these laws.

Loss of our information and computer systems could adversely affect our business.

We are dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil, natural gas and NGLs and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Our acquisition, development, optimization and exploitation projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our ability to access or grow production and reserves.

The oil, natural gas and NGL industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, development, optimization and exploitation of oil and natural gas reserves. Funding sources for our capital expenditures have included proceeds from bank borrowings, cash from our partners and cash flow from operating activities. Our management has collectively invested more than $500 million in us since our inception. Following the completion of this offering, we expect that we will not be able to rely on our management or our partners for capital and will need to utilize the public equity or debt markets and bank financings to fund acquisitions and capital expenditures. We expect to fund the remainder of our 2022 and our 2023 capital expenditures with cash generated by operations and borrowings under our Credit Facility; however, our cash flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the volume of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves;
- the extent and levels of our derivative activities;
- the levels of our operating expenses; and
- our ability to borrow under our Credit Facility.

If our revenues or the borrowing base under our Credit Facility decrease as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. Even if we can obtain debt financing on terms acceptable to us, the issuance of additional indebtedness would require that a portion of our cash flows from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flows from operations to fund working capital, capital expenditures and acquisitions. Additionally, the market demand for equity issued by master limited partnerships has been significantly lower in recent years than it has been historically, which may make it more challenging for us to finance our capital expenditures with the issuance of additional equity. The issuance of additional equity securities may be dilutive to our unitholders. If cash flows generated by our operations or available borrowings under our Credit Facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and would adversely affect our business, financial condition and results of operations. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Continuing political and social concerns about the issues of climate change may result in changes to our business and significant expenditures, including litigation-related expenses.

Increasing attention to global climate change has resulted in increased investor attention and an increased risk of public and private litigation, which could increase our costs or otherwise adversely affect our business. For example, shareholder activism has recently been increasing in our industry, and shareholders may attempt to effect changes to our business or governance, whether by shareholder proposals, public campaigns, proxy solicitations or otherwise. Additionally, cities, counties, and other governmental entities in several states in the U.S. began filing lawsuits against energy companies in 2017. The lawsuits seek damages allegedly associated with climate change, and the plaintiffs are seeking unspecified damages and abatement under various tort theories. Similar lawsuits may be filed in other jurisdictions. We believe these lawsuits are an inappropriate vehicle to address the challenges associated with climate change and will vigorously defend against them for lacking factual and legal merit. The ultimate outcome and impact to us of any such litigation cannot be predicted with certainty, and we could incur substantial legal costs associated with defending these and similar lawsuits in the future. Additionally, any of these risks could result in unexpected costs, negative sentiments about our company, disruptions in our operations, increases to our operating expenses and reduced demand for our products, which in turn could have an adverse effect on our business, financial condition and results of operations.

Risks Related to Environmental and Regulatory Matters

We are subject to stringent federal, state and local laws and regulations related to environmental and occupational health and safety issues that could adversely affect the cost or feasibility of conducting our operations or expose us to significant liabilities.

Our operations are subject to numerous stringent federal, state and local laws and regulations governing occupational safety and health aspects of our operations, the discharge of materials into the environment and the protection of the environment and natural resources (including threatened and endangered species). These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of a permit before conducting drilling and other regulated activities; the restriction of types, quantities and concentration of materials that may be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations, and reclamation and restoration costs. Numerous governmental authorities, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations or specific projects and limit our growth and revenue.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and other hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations and waste disposal practices at our leased and owned properties. Spills or other releases of regulated substances, including such spills and releases that occur in the future, could expose us to material losses, expenditures and liabilities under applicable environmental laws and regulations. Under certain of such laws and regulations, we could be subject to strict, joint and several liability for the removal or remediation of contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted. We may not be able to recover some or any of these costs from insurance. The trend in environmental regulation has been towards more stringent requirements, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition. For example, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple sites into a single source for air quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements.

In October 2015, the EPA issued a new lower National Ambient Air Quality Standard ("NAAQS") for ozone of 70 parts per billion. In 2017, the EPA designated certain counties in southeastern New Mexico and West Texas located in the Permian Basin attainment/unclassifiable for the 2015 ozone NAAQS. However, in June 2022, EPA announced that it is considering a discretionary redesignation for these counties based on current monitoring data and other air quality factors. If the Permian Basin counties in which we operate were redesignated as nonattainment areas, this could subject us to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements and increased permitting delays and costs.

The EPA has also imposed increasingly stringent performance standards on oil and gas operations. In 2016, the EPA issued regulations under NSPS OOOOa that require operators to reduce methane and volatile organic compound ("VOC") emissions from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations. In November 2021, the EPA proposed a rule to further reduce methane and VOC emissions from new and existing sources in the oil and natural gas sector. The proposed rule would establish standards of performance for sources that commence construction, modification or reconstruction after the date the proposed rule is published in the Federal Register and would establish emissions guidelines, which will inform state plans to establish standards for existing sources. State agencies have similarly imposed increasing restrictions on emissions from oil and gas operations. For example, in 2022, the New Mexico Environment Department adopted new regulations establishing emission reduction requirements for storage vessels, compressors, turbines, heaters, engines, dehydrators, pneumatic devices, produced water management units, and other equipment and processes. Compliance with these more stringent standards and other environmental regulations at the federal or state levels could delay or prohibit our ability to obtain permits for operations or require us to install additional pollution control equipment, the costs of which could be significant. See "Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters" for a further description of the laws and regulations that affect us.

Should we fail to comply with all applicable regulatory agency administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005 ("EPAct 2005"), the Federal Energy Regulatory Commission (the "FERC") has civil penalty authority under the Natural Gas Act of 1938 ("NGA") to impose penalties for current violations of $1,388,496 per violation per day. The FERC may also impose administrative and criminal remedies and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and regulations pertaining to those and other matters may be considered or adopted by FERC from time to time. Additionally, the Federal Trade Commission ("FTC") has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to $1,323,791 per violation per day, and the Commodity Futures Trading Commission ("CFTC") prohibits market manipulation in the markets regulated by the CFTC, including similar anti manipulation authority with respect to swaps and futures contracts as that granted to the CFTC with respect to oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of $1,303,559 or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in "Business—Regulation of the Oil and Natural Gas Industry."

Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil, natural gas and NGL exploration and production activities, and reduce demand for the oil, natural gas and NGLs we produce.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. The federal government has also increased regulation of methane from oil and gas facilities in recent years. For example, in 2016, the EPA issued regulations under NSPS OOOOa that require operators to reduce methane and VOC emissions from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations. In November 2021, the EPA proposed a rule to further reduce methane and VOC emissions from new and existing sources in the oil and natural gas sector. The proposed rule would establish standards of performance for sources that commence construction, modification or reconstruction after the date the proposed rule is published in the Federal Register and would establish emissions guidelines, which will inform state plans to establish standards for existing sources. The EPA is currently seeking public comments on its proposal, which the EPA hopes to finalize by the end of 2022. Once finalized, the regulations are likely to be subject to legal challenge. Emissions guidelines will also need to be incorporated into the states' implementation plans, which will need to be approved by the EPA in individual rulemakings that could also be subject to legal challenge. If finalized, these increasingly stringent methane and VOC requirements on new facilities, or the application of new requirements to existing facilities, could result in additional restrictions on our operations and increased compliance costs, which could be significant. Given the long-term trend toward increasing regulation, we expect there will be additional future federal GHG regulations of the oil and gas industry.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. For example, the New Mexico Oil Conservation Commission has adopted regulations to restrict the venting or flaring of methane from both upstream and midstream operations. Internationally, the United Nations-sponsored "Paris Agreement" requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States' emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered again in Glasgow at the 26th Conference to the Parties on the UN Framework Convention on Climate Change ("COP26"), during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-CO_2 GHGs. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. President Biden also agreed that same month to cooperate with Chinese leader Xi

Jinping on accelerating progress toward the adoption of clean energy. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement, COP26, or other international conventions cannot be predicted at this time. However, to the extent these developments result in new restrictions on oil and gas operations, increase operational costs, or otherwise reduce the demand for oil and gas, they could have a material adverse effect on our business.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates elected to public office. President Biden has issued several executive orders focused on addressing climate change, including items that may impact our costs to produce, or demand for, oil and gas. Additionally, in November 2021, the Biden Administration released "The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050," which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-CO_2 GHG emissions, such as methane and nitrous oxide. The Biden Administration is also considering revisions to the leasing and permitting programs for oil and gas development on federal lands.

Litigation risks are also increasing, as a number of entities have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to climate change. Suits have also been brought against such companies under shareholder and consumer protection laws, alleging that companies have been aware of the adverse effects of climate change but failed to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into other sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. President Biden signed an executive order calling for the development of a "climate finance plan" and, separately, the Federal Reserve has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. More recently, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Additionally, the SEC recently proposed new rules relating to the disclosure of a range of climate-related risks. The proposed rule contains several new disclosure obligations, including (i) disclosure on an annual basis of a registrant's scope 1 and scope 2 greenhouse gas emissions, (ii) third-party independent attestation of the same for accelerated and large accelerated filers, (iii) disclosure on an annual basis of a registrant's scope 3 greenhouse gas emissions for accelerated and large accelerated filers, (iv) disclosure on how the board of directors of our general partner (the "Board") and management oversee climate-related risks and certain climate-related governance items, (v) disclosure of information related to a registrant's publicly announced climate-related targets, goals and/or transitions plans and (vi) disclosure on whether and how climate-related events and transition activities impact line items above a threshold amount on a registrant's consolidated financial statements, including the impact of the financial estimates and the assumptions used. While we would likely be subject to the longer proposed phase-in for the reporting requirements as an emerging growth company, we are currently assessing this rule and cannot predict the costs of implementation or any potential adverse impacts resulting from the rule should it be adopted as proposed; however, we expect these costs to be substantial. In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon intensive sectors.

The adoption and implementation of new or more stringent international, federal, regional or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas. Additionally, political, litigation and financial risks may result in our restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

Increased attention to ESG matters and conservation measures may adversely impact our business.

Increasing attention to climate change, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary ESG disclosures, and consumer demand for alternative forms of energy may result in increased costs, reduced demand for our products, reduced profits, increased investigations and litigation, and negative impacts on the price of our common units and access to capital markets. Increasing attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against us or our operators. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters in the future, many of the statements in those voluntary disclosures may be on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying and measuring many ESG matters.

In addition, organizations that voluntarily provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our access to and costs of capital. Also, institutional lenders may decide not to provide funding for fossil fuel energy companies based on climate change related concerns, which could affect our access to capital for potential growth projects.

We may face various risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities.

Opposition toward oil and gas drilling and development activity has been growing globally. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental compliance and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain projects such as the development of oil and gas shale plays. For example, environmental activists continue to advocate for increased regulations or bans on shale drilling and hydraulic fracturing in the United States, even in jurisdictions that are among the most stringent in their regulation of the industry. Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms and reduction in lease size;
- restrictions on installation or operation of production, gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing, or disposal of related waste materials, such as hydraulic fracking fluids and production;
- increased severance and/or other taxes;
- cyber-attacks;
- legal challenges or lawsuits;
- negative publicity about our business or the oil and gas industry in general;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

We may need to incur significant costs associated with responding to these initiatives. Complying with any resulting additional legal or regulatory requirements that are substantial could have a material adverse effect on our business, financial condition, cash flows, results of operations and ability to pay distributions on our common units.

Prolonged negative investor sentiment toward upstream natural gas and oil focused companies could limit our access to capital funding, which would constrain liquidity.

Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other sectors have led to lower natural gas and oil representation in certain key equity market indices. Some investors, including certain pension funds, private equity funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the natural gas and oil sector based on social and environmental considerations. Certain other stakeholders have pressured commercial and investment banks to stop funding hydrocarbon extraction, transportation or refining. If this negative sentiment continues or worsens, it may reduce the availability of capital funding for potential development projects, each of which could have a material adverse effect our financial condition, results of operations, cash flows and ability to pay distributions on our common units.

Conservation measures and technological advances could reduce demand for oil, natural gas and NGLs.

Fuel conservation measures, alternative fuel requirements, increasing availability of, and consumer and industrial/commercial demand for, alternatives to oil, natural gas and NGLs (e.g., alternative energy sources) and products manufactured with, or powered by, non-oil and gas sources (e.g., electric vehicles and renewable residential and commercial power supplies), and technological advances in fuel economy and energy generation, transmission, storage and consumption of energy (e.g., wind, solar and hydrogen power, smart grid technology and battery technology) could reduce demand for oil, natural gas and NGLs. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, our business could be impacted by governmental initiatives to incentivize the conservation of energy or the use of alternative energy sources. For example, in November 2021, the Biden Administration released "The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050," which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-CO2 GHG emissions, such as methane and nitrous oxide. Further, the U.S. Department of Transportation recently issued more stringent fuel economy standards. These initiatives or similar state or federal initiatives to reduce energy consumption or incentivize a shift away from fossil fuels could reduce demand for hydrocarbons and have a material adverse effect on our earnings, cash flows and financial condition.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of unconventional natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into targeted geological formations to fracture the surrounding rock and stimulate production. Nearly all of our wells are drilled conventionally; however, from time to time a small percentage of our wells are horizontally completed.

Hydraulic fracturing is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA published final CAA regulations in 2012 and, more recently, in June 2016 governing CAA performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting and separately published in June 2016 an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances. In addition, the BLM finalized rules in March 2015 establishing stringent standards relating to hydraulic fracturing on federal and American Indian lands, including well casing and wastewater storage requirements and an obligation for exploration and production operators to disclose what chemicals they are using in fracturing activities. In December 2017, BLM issued a final rule repealing the 2015 hydraulic fracturing rule. The BLM's rescission of the rule was challenged by several environmental groups and states in the United States District Court for the Northern District of California. The United States District Court for the Northern District of California upheld the BLM's recission in a March 2020 decision. Additionally, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Meanwhile, states have continued to regulate hydraulic fracturing.

In the event that a new, federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may incur additional costs to comply with such requirements when horizontally completing wells, which may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities, which could in turn have a material adverse effect on our business and results of operations.

See "Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters" for a further description of the laws and regulations that affect us.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse impact on our ability to develop and produce our reserves.

The third parties on whom we rely for transportation services are subject to complex federal, state, tribal and local laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state, tribal and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulation. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to our unitholders. Please read "Business and Properties—Environmental Matters and Regulation" and "Business and Properties—Other Regulation of the Oil and Natural Gas Industry" for a description of the laws and regulations that affect the third parties on whom we rely.

Derivatives regulation could have an adverse effect on our ability to use derivative contracts to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over the counter derivatives market and of entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, the CFTC has adopted rules that place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. These limitations could increase the costs to us of entering into, or lessen the availability of, derivative contracts to hedge or mitigate our exposure to volatility in oil, gas and NGL prices and other commercial risks affecting our business. The Dodd-Frank Act and CFTC rules will also require us, in connection with certain derivatives activities, to comply with clearing and trade execution requirements (or to qualify for an exemption to such requirements). In addition, the CFTC and certain banking regulators have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end user exception to the mandatory clearing, trade execution and margin requirements for swaps entered to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, if any of our swaps do not qualify for the commercial end user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow. It is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us or the timing of such effects. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and CFTC rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and CFTC rules is to lower commodity prices. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, the impact of which is not clear at this time.

We may be involved in legal proceedings that could result in substantial liabilities.

Like many oil and natural gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of our business. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties or sanctions may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil, natural gas and NGLs, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- well blowouts;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapses;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Also, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or fully covered by insurance and any delay in the payment of insurance proceeds for covered events could have a material adverse effect on our business, financial condition and results of operations.

Limitation or restrictions on our ability to obtain water may have an adverse effect on our operating results.

Water is an essential component of shale oil and natural gas development during both the drilling and hydraulic fracturing processes. Our access to water to be used in these processes may be adversely affected due to reasons such as periods of extended drought, private, third party competition for water in localized areas or the implementation of local or state governmental programs to monitor or restrict the beneficial use of water subject to their jurisdiction for hydraulic fracturing to assure adequate local water supplies. In addition, treatment and disposal of water is becoming more highly regulated and restricted. Thus, our costs for obtaining and disposing of water could increase significantly. Our inability to locate or contractually acquire and sustain the receipt of sufficient amounts of water could adversely impact our exploration and production operations and have a corresponding adverse effect on our business, results of operations and financial condition.

Risks Inherent in an Investment in Us

Our general partner and its affiliates own a controlling interest in us and will have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

Our general partner will have control over all decisions related to our operations. Upon consummation of this offering, Bob R. Simpson, our Chief Executive Officer, Brent W. Clum, our President of Business Operations and Chief Financial Officer, Keith A. Hutton, our President of Production and Development, Scott T. Agosta, our Chief Accounting Officer, Vaughn O. Vennerberg II, our Executive Vice President, and Timothy L. Petrus, our former Executive Vice President (collectively, the "Founders") will own all of the membership interests in our general partner. The Founders will own an aggregate of approximately   % of our outstanding common units. Although our general partner has a duty to manage us in a manner that is not adverse to the best interests of us and our unitholders, the executive officers and directors of our general partner also have a duty to manage our general partner in a manner that is not adverse to the best interests of its owners. As a result of these relationships, conflicts of interest may arise in the future between the Founders and their respective affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our common unitholders. These conflicts include, among others, the following:

- Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limiting our general partner's liabilities and restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- Neither our partnership agreement nor any other agreement requires the Founders or their respective affiliates (other than our general partner) to pursue a business strategy that favors us;

- The Founders and their affiliates are not limited in their ability to compete with us, including with respect to future acquisition opportunities, and are under no obligation to offer or sell assets to us;
- Our general partner determines the amount and timing of our development operations and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership interests, other investments, including investment capital expenditures in other partnerships with which our general partner is or may become affiliated, and cash reserves, each of which can affect the amount of cash that is distributed to unitholders;
- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- Our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- Our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- Our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Please read “Certain Relationships and Related Party Transactions” and “Conflicts of Interest and Duties.”

Our partnership agreement does not restrict our Founders and their respective affiliates from competing with us. Certain of our directors and officers may in the future spend significant time serving, and may have significant duties with, investment partnerships or other private entities that compete with us in seeking out acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. Affiliates of our general partner are not prohibited from owning projects or engaging in businesses that compete directly or indirectly with us. Similarly, our partnership agreement does not limit our Founders’ or their respective affiliates’ ability to compete with us and our Founders do not have any obligation to present business opportunities to us.

In addition, certain of our officers and directors may in the future hold similar positions with investment partnerships or other private entities that are in the business of identifying and acquiring mineral and royalty interests. In such capacities, these individuals would likely devote significant time to such other businesses and would be compensated by such other businesses for the services rendered to them. The positions of these directors and officers may give rise to duties that are in conflict with duties owed to us. In addition, these individuals may become aware of business opportunities that may be appropriate for presentation to us as well as the other entities with which they are or may be affiliated. Due to these potential future affiliations, they may have duties to present potential business opportunities to those entities prior to presenting them to us, which could cause additional conflicts of interest. Our Founders and their respective affiliates will be under no obligation to make any acquisition opportunities available to us, except as provided for under the contribution agreement. See "Conflicts of Interest and Duties."

Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors, our Founders and their respective affiliates. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and holders of our common units.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow our reserves and production and make acquisitions.

Our partnership agreement provides that we distribute all of our available cash each quarter. As a result, we expect to rely primarily upon our cash reserves and external financing sources, including the issuance of additional common units and other partnership securities and borrowings under our Credit Facility, to fund future acquisitions and finance our growth. To the extent we are unable to finance growth with our cash reserves and external sources of capital, the requirement in our partnership agreement to distribute all of our available cash may impair our ability to grow.

A number of factors will affect our ability to issue securities and borrow money to finance growth, as well as the costs of such financings, including:

- general economic and market conditions, including interest rates, prevailing at the time we desire to issue securities or borrow funds;
- conditions in the oil and gas industry;
- the market price of, and demand for, our common units;
- our results of operations and financial condition; and
- prices for oil, natural gas and NGLs.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or our Credit Facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Our partnership agreement replaces our general partner's fiduciary duties to our unitholders with contractual standards governing its duties, and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with different contractual standards. For example, our partnership agreement provides that:

- whenever our general partner (acting in its capacity as our general partner), the Board or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the Board and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was not adverse to our best interests, and, except as specifically provided by our partnership agreement, will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or equitable principle;

- our general partner may make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in the partnership agreement does not provide for a clear course of action. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

  - how to allocate corporate opportunities among us and its other affiliates;
  - whether to exercise its limited call right;
  - whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the Board;
  - how to exercise its voting rights with respect to the units it owns;
  - whether to sell or otherwise dispose of any units or other partnership interests it owns; and
  - whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

- our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith;

- our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- our general partner will not be in breach of its obligations under the partnership agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:

  - approved by the conflicts committee of the Board, although our general partner is not obligated to seek such approval;

  - approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

  - determined by the Board to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

  - determined by the Board to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the conflicts committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the Board determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the third and fourth sub-bullet points above, then it will be presumed that, in making its decision, the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the Partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity and incur debt.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. In addition, as with other yield-oriented securities, our unit price is impacted by the level of our cash distributions to our unitholders and implied distribution yield. This implied distribution yield is often used by investors to compare and rank similar yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity or incur debt. See "—Increased costs of capital could adversely affect our business."

Units held by persons who our general partner determines are not eligible holders will be subject to redemption.

To comply with U.S. laws with respect to the ownership of interests in oil and natural gas leases on U.S. federal lands, we have adopted certain requirements regarding those investors who may own our common units. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in oil and natural gas leases on federal lands. As of the date hereof, Eligible Holder means:

- a citizen of the United States;
- a corporation organized under the laws of the United States or of any state thereof;
- a public body, including a municipality; or
- an association of United States citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof.

Onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof. Unitholders who are not persons or entities who meet the requirements to be an Eligible Holder run the risk of having their common units redeemed by us at the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. Please read "Description of the Common Units—Transfer Agent and Registrar—Transfer of Common Units" and "The Partnership Agreement—Non-Citizen Unitholders; Redemption."

Our unitholders have limited voting rights and are not entitled to elect our general partner or the Board, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The Board, including the independent directors, is chosen entirely by the Founders, as a result of their ownership of our general partner, and not by our unitholders. Please read "Management—Management of TXO Energy Partners" and "Certain Relationships and Related Party Transactions." Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our general partner will have control over all decisions related to our operations. Since, upon consummation of this offering, our general partner will continue to be owned by the Founders, who collectively with the other Existing Owners, will own and control the voting of an aggregate of approximately % of our outstanding common units, the other unitholders will not have an ability to influence any operating decisions and will not be able to prevent us from entering into any transactions. However, our partnership agreement can be amended with the consent of our general partner and the approval of the holders of a majority of our outstanding common units (including common units held by the Existing Owners and their affiliates). Assuming we do not issue any additional common units and the Existing Owners not transfer any of their common units, the Existing Owners will have the ability to amend our partnership agreement, including our policy to distribute all of our cash available for distribution to our unitholders, without the approval of any other unitholder. Furthermore, the goals and objectives of the Existing Owners and their affiliates that hold our common units relating to us may not be consistent with those of a majority of the other unitholders. Please read "—Our general partner and its affiliates own a controlling interest in us and will have conflicts of interest with, and owe limited duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders."

Even if our unitholders are dissatisfied, they cannot remove our general partner without its consent.

The public unitholders will be unable initially to remove our general partner without its consent because affiliates of our general partner will own sufficient units upon completion of this offering to be able to prevent the removal of our general partner. The vote of the holders of at least 66 ⅔% of all outstanding units voting together as a single class is required to remove our general partner. Following consummation of this offering, the Founders will own approximately % of our outstanding voting units, which will enable those holders, collectively, to prevent the removal of our general partner.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the Founders, who own our general partner, from transferring all or a portion of their ownership interests in our general partner to a third party. The new owner of our general partner would then be in a position to replace the Board and officers of our general partner with their own choices and thereby influence the decisions made by the Board and officers.

We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval.

Our partnership agreement does not limit the number of additional common units that we may issue at any time without the approval of our unitholders. In addition, we may issue an unlimited number of units that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' limited voting rights by providing that any common units held by a person, entity or group owning 20% or more of any class of common units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such common units with the prior approval of the Board, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the ability of our common unitholders to influence the manner or direction of management.

Once our common units are publicly traded, the Existing Owners may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

After the sale of the common units offered hereby, the Existing Owners will own common units, or approximately % of our limited partner interests. Once our common units are publicly traded, the sale of these units in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the then outstanding common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your common units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units and then exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act. At the closing of this offering, affiliates of our general partner will own approximately % of our common units. For additional information about this call right, please read "The Partnership Agreement—Limited Call Right."

Our partnership agreement will designate the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which would limit our unitholders' ability to choose the judicial forum for disputes with us or our general partner's directors, officers or other employees. Our partnership agreement also provides that any unitholder bringing an unsuccessful action will be obligated to reimburse us for any costs we have incurred in connection with such unsuccessful action.

Our partnership agreement will provide that, with certain limited exceptions, the Court of Chancery of the State of Delaware will be the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners, (4) asserting a claim arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act") or (5) asserting a claim against us governed by the internal affairs doctrine. In addition, if any unitholder brings any of the aforementioned claims, suits, actions or proceedings and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such person shall be obligated to reimburse us and our affiliates for all fees, costs and expenses of every kind and description, including but not limited to all reasonable attorneys' fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding. This provision would not apply to claims brought to enforce a duty or liability created by the Exchange Act, the Securities Act or any other claim for which the federal courts have exclusive jurisdiction. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our amended and restated certificate of limited partnership inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations. Our partnership agreement also provides that each limited partner waives the right to trial by jury in any such claim, suit, action or proceeding. If a lawsuit is brought against us under our partnership agreement, it may be heard only by a judge or justice of the applicable trial court, which would be conducted according to different civil procedures and may result in different outcomes than a trial by jury would have, including results that could be less favorable to the plaintiffs in any such action. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations, provisions and potential reimbursement obligations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions or proceedings. These provisions may have the effect of discouraging lawsuits against us and our general partner's directors and officers. For additional information about the exclusive forum provision of our partnership agreement, please read "The Partnership Agreement—Applicable Law; Forum, Venue and Jurisdiction."

The NYSE does not require a publicly traded partnership like us to comply, and we do not intend to comply, with certain of its governance requirements generally applicable to corporations.

We have applied to list our common units on the NYSE. Because we will be a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to stockholders of certain corporations that are subject to all of the NYSE's corporate governance requirements. Please read "Management—Management of TXO Energy Partners"

Our unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. A unitholder could be liable for our obligations as if it was a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or

- a unitholder's right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Please read "The Partnership Agreement—Limited Liability" for a discussion of the implications of the limitations of liability on a unitholder.

Our unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make distributions to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to us are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Transferees of common units are liable both for the obligations of the transferor to make contributions to us that are known to the transferee at the time of the transfer and for unknown obligations if the liabilities could be determined from our partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Our unitholders may have limited liquidity for their common units, a trading market may not develop for the common units and our unitholders may not be able to resell their common units at the initial public offering price.

Prior to this offering, there has been no public market for the common units. After this offering, there will be publicly traded common units. We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. Our unitholders may not be able to resell their common units at or above the initial public offering price. Additionally, a lack of liquidity would likely result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

If our common unit price declines after the initial public offering, our unitholders could lose a significant part of their investment.

The initial public offering price for the common units will be determined by negotiations between us and the representatives of the underwriters and may not be indicative of the market price of the common units that will prevail in the trading market. The market price of our common units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in commodity prices;
- changes in securities analysts' recommendations and their estimates of our financial performance;
- public reaction to our press releases, announcements and filings with the SEC;

- fluctuations in broader securities market prices and volumes, particularly among securities of oil and natural gas companies and securities of publicly traded limited partnerships and limited liability companies;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other oil and natural gas companies;
- variations in the amount of our quarterly cash distributions to our unitholders;
- changes in tax law;
- an election by our general partner to convert or restructure us as a taxable entity;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements that apply to other public companies, including those relating to auditing standards and disclosure about our executive compensation.

The JOBS Act contains provisions that, among other things, relax certain reporting requirements for “emerging growth companies,” including certain requirements relating to auditing standards and compensation disclosure. We are classified as an emerging growth company. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things, (1) provide an auditor’s attestation report on management’s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002, (2) comply with any new requirements adopted by the Public Company Accounting Oversight Board (“PCAOB”) requiring mandatory audit firm rotation or a supplement to the auditor’s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (3) comply with any new audit rules adopted by the PCAOB after April 5, 2012 unless the SEC determines otherwise or (4) provide certain disclosure regarding executive compensation required of larger public companies.

Taking advantage of the longer phase-in periods for the adoption of new or revised financial accounting standards applicable to emerging growth companies may make our common units less attractive to investors.

We intend to take advantage of all of the reduced reporting requirements and exemptions available to emerging growth companies under the JOBS Act, including the longer phase-in periods for the adoption of new or revised financial accounting standards under Section 107 of the JOBS Act, until we are no longer an emerging growth company. If we were to subsequently elect instead to comply with these public company effective dates, such election would be irrevocable pursuant to Section 107 of the JOBS Act.

Our election to use the phase-in periods permitted by this election may make it difficult to compare our financial statements to those of non-emerging growth companies and other emerging growth companies that have opted out of the longer phase-in periods under Section 107 of the JOBS Act and who will comply with new or revised financial accounting standards. We cannot predict if investors will find our common units less attractive because we will rely on these exemptions. If some investors find our common units less attractive as a result, there may be a less active trading market for our common units and our common unit price may be more volatile. Under the JOBS Act, emerging growth companies can delay adopting new or revised accounting standards until such time as those standards apply to private companies.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

Our general partner may elect to convert or restructure us from a partnership to an entity taxable as a corporation for U.S. federal income tax purposes without unitholder consent and without taking into account the immediate and long-term tax consequences to our limited partners.

Under the partnership agreement, our general partner may, without unitholder approval, cause us to be treated as an entity taxable as a corporation or subject to entity-level taxation for U.S. federal income tax purposes, whether by election of the partnership or conversion of the partnership or by any other means or methods. In addition and as part of such determination, our general partner and its affiliates may choose to retain their partnership interests in us and cause our interests held by other persons to be converted into or exchanged for interests in a new entity, taxable as a corporation or subject to entity-level taxation for U.S. federal purposes, whose sole assets are interests in us. The general partner may take any of the foregoing actions if it in good faith determines (meaning it subjectively believes) that such action is not adverse to our best interests. In making such determination, however, our general partner is not required to take into account the immediate and long-term tax consequences to our limited partners. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. The tax liability, if any, of a unitholder as a result of such an event may be material to such unitholder and may vary depending on the unitholder's particular situation and may vary from the tax liability of our general partner and us. Our general partner will have no duty or obligation to make any such determination or take any such actions, however, and may decline to do so free of any duty or obligation whatsoever to us or our limited partners, including any duty to act in a manner not adverse to the best interests of our limited partners. Please read “The Partnership Agreement—Election to be Treated as a Corporation.”

We will incur increased costs as a result of being a publicly traded partnership.

We have no history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting and other expenses that we did not incur prior to this offering. In addition, the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the NYSE, require publicly traded entities to adopt various corporate governance practices that will further increase our costs. The amount of our expenses or reserves for expenses, including the costs of being a publicly traded partnership will reduce the amount of cash we have for distribution to our unitholders. As a result, the amount of cash we have available for distribution to our unitholders will be affected by the costs associated with being a public company.

Prior to this offering, we have not filed reports with the SEC. Following this offering, we will become subject to the public reporting requirements of the Exchange Act. We expect these rules and regulations to increase certain of our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a publicly traded company, we are required to have at least three independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our SEC reporting requirements.

We also expect to incur additional expense in order to obtain director and officer liability insurance. Because of the limitations in coverage for directors, it may be more difficult for us to attract and retain qualified persons to serve on the Board or as executive officers.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our units or if our operating results do not meet their expectations, our unit price could decline.

The trading market for our common units will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our unit price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common units or if our operating results do not meet their expectations, our unit price could decline.

Tax Risks to Common Unitholders

In addition to reading the following risk factors, prospective unitholders should read “Material U.S. Federal Income Tax Consequences” for a more complete discussion of the expected material federal income tax consequences of owning and disposing of our common units.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (the “IRS”) were to treat us as a corporation for federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders could be reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we will be treated as a corporation for federal income tax purposes unless we satisfy a “qualifying income” requirement. Based on our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") with respect to our classification as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate and we would also likely pay additional state and local income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to our unitholders could be reduced. Thus, treatment of us as a corporation could result in a reduction in the anticipated cash-flow and after-tax return to our unitholders, which would cause a reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, capital, and other forms of business taxes, as well as subjecting nonresident partners to taxation through the imposition of withholding obligations and composite, combined, group, block, or similar filing obligations on nonresident partners receiving a distributive share of state "sourced" income. We currently own property or do business in New Mexico, Texas and Colorado, among other states. Imposition on us of any of these taxes in jurisdictions in which we own assets or conduct business or an increase in the existing tax rates could result in a reduction in the anticipated cash-flow and after-tax return to our unitholders, which would cause a reduction in the value of our common units.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation. From time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships or an investment in our common units, including elimination of partnership tax treatment for certain publicly traded partnerships.

Any changes to federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to be treated as a partnership for federal income tax purposes or otherwise adversely affect our business, financial condition or results of operations. Any such changes or interpretations thereof could adversely impact the value of an investment in our common units.

Certain U.S. federal income tax incentives currently available with respect to oil and natural gas exploration and production may be reduced or eliminated as a result of future legislation.

In recent years, legislation has been proposed that would, if enacted, make significant changes to United States tax laws, including the reduction or elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units. Please Read “Material U.S. Federal Income Tax Consequences—Recent Legislative Developments.”

We will prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We will generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of the units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Please read “Material U.S. Federal Income Tax Consequences—Disposition of Common Units—Allocations Between Transferors and Transferees.”

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units and the cost of any IRS contest will reduce our cash available for distribution to unitholders.

The IRS has made no determination as to our status as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of the positions we take. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, our costs of any contest with the IRS, principally legal, accounting and related fees, will be indirectly borne by our unitholders because the costs will reduce our cash available for distribution.

If the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case we would pay the taxes directly to the IRS. If we bear such payment, our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Our general partner would cause us to pay the taxes (including any applicable penalties and interest) directly to the IRS. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own common units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced.

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount from the cash that we distribute, our unitholders may be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

Tax gains or losses on the disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in the unitholder's common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such common units at a price greater than the unitholder's tax basis in those common units, even if the price received is less than the unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items such as depreciation, depletion, amortization and IDCs. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of the cash received from the sale. Please read "Material U.S. Federal Income Tax Consequences—Disposition of Common Units—Recognition of Gain or Loss."

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

Our ability to deduct interest paid or accrued on indebtedness properly allocable to a trade or business ("business interest") may be limited in certain circumstances. Should our ability to deduct business interest be limited, the amount of taxable income allocated to our unitholders in the taxable year in which the limitation is in effect may increase. However, in certain circumstances, a unitholder may be able to utilize a portion of a business interest deduction subject to this limitation in future taxable years. Prospective unitholders should consult their tax advisors regarding the impact of this business interest deduction limitation on an investment in our common units.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investments in our common units bytax-exempt entities, such as individual retirement accounts ("IRAs") or other retirement plans, andnon-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. A tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor regarding the impact of these rules on an investment in our common units. Please read “Material U.S. Federal Income Tax Consequences—Tax-Exempt Organizations and other Investors.”

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business (“effectively connected income”). Income allocated to our unitholders and any gain from the sale of our common units will generally be considered to be “effectively connected” with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that common unit.

Moreover, upon the sale, exchange or other disposition of a common unit by anon-U.S. unitholder, the transferee is generally required to withhold 10% of the amount realized on such sale, exchange or other disposition if any portion of the gain on such sale, exchange or other disposition would be treated as effectively connected with a U.S. trade or business. The U.S. Department of the Treasury and the IRS have issued final regulations providing guidance on the application of these rules for transfers of certain publicly traded partnership interests, including transfers of our common units. Under these regulations, the “amount realized” on a transfer of our common units will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and such broker will generally be responsible for the relevant withholding obligations. Distributions to non-U.S. unitholders may also be subject to additional withholding under these rules to the extent a portion of a distribution is attributable to an amount in excess of our cumulative net income that has not previously been distributed. The U.S. Department of the Treasury and the IRS have provided that these rules will generally not apply to transfers of our common units occurring before January 1, 2023. Non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units. Please read “Material U.S. Federal Income Tax Consequences—Tax-Exempt Organizations and other Investors.”

We will treat each purchaser of our common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation, depletion and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholder’s tax returns.

Our common unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes imposed by the various jurisdictions in which we do business or own property now or in the future, even if the unitholder does not live in any of those jurisdictions. Our common unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property or conduct business in New Mexico, Texas and Colorado, among other states. New Mexico and Colorado each impose a personal income tax. Texas does not currently impose a personal income tax on individuals, but it does impose an entity level tax (to which we will be subject) on corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal or corporate income tax. It is the responsibility of each unitholder to file its own federal, state and local tax returns, as applicable.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from lending their common units.

We will adopt certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the amount, character and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

USE OF PROCEEDS

We intend to use the expected net proceeds of approximately $ million from this offering, based upon the assumed initial public offering price of $ per common unit (the midpoint of the price range set forth on the cover of this prospectus), after deducting underwriting discounts and estimated expenses, to repay in full amounts outstanding under our revolving credit facility (our "Credit Facility"), with any remaining amounts to be used for working capital and general partnership purposes.

If and to the extent the underwriters exercise their option to purchase additional common units, the number of common units purchased by the underwriters pursuant to such exercise will be issued to the public. If the underwriters exercise their option to purchase additional common units in full, the additional net proceeds would be approximately $ million. The net proceeds from any exercise of such option will be used for general partnership purposes. Please read "Underwriting."

As of March 31, 2022, we had $130 million of outstanding borrowings under our Credit Facility, which has a maturity date of November 1, 2025. Borrowings outstanding under our Credit Facility bore interest at a weighted average rate of 4.1% per annum as of March 31, 2022. The outstanding borrowings under our Credit Facility were incurred to partially fund the Chevron Vacuum Acquisition.

A $1.00 increase or decrease in the assumed initial public offering price of $ per common unit would cause the net proceeds from this offering, after deducting underwriting discounts and estimated offering expenses payable by us, to increase or decrease, respectively, by approximately $ million. In addition, we may also increase or decrease the number of common units we are offering. Each increase of million common units offered by us, together with a concurrent $1.00 increase in the assumed public offering price of $ per common unit, would increase net proceeds to us from this offering by approximately $ million. Similarly, each decrease of million common units offered by us, together with a concurrent $1.00 decrease in the assumed initial offering price of $ per common unit, would decrease the net proceeds to us from this offering by approximately $ million.

CAPITALIZATION

The following table shows:

- historical capitalization as of March 31, 2022; and
- our capitalization as of March 31, 2022 as adjusted to give effect to this offering and the application of the net proceeds from this offering as described under "Use of Proceeds."

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, our historical and unaudited pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations." For a description of the pro forma adjustments, please read our Unaudited Pro Forma Condensed Financial Statements.

	As of March 31, 2022 (Historical)	As of March 31, 2022 (As Adjusted)
	(In thousands)	
Cash and cash equivalents	$ 15,356	
Long-term debt	$ 137,100	
Members'/partners' capital/net equity:		
Common equity held by public	—	
Common equity held by the Existing Owners	$ 235,407	
Series 3 Preferred Equity	$ 34,295	
Series 5 Preferred Equity	$ 206,074	
Total members'/partners' capital/net equity	$ 475,776	
Total capitalization	$ 612,876	

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DILUTION

Dilution is the amount by which the offering price paid by the purchasers of common units sold in this offering will exceed the net tangible book value per unit after this offering. Net tangible book value is our total tangible assets less total liabilities. Assuming an initial offering price of $ per common unit (the midpoint of the price range set forth on the cover of this prospectus), on a pro forma basis as of March 31, 2022, after giving effect to this offering of common units and the application of the related net proceeds, our net tangible book value would have been $ million, or $ per unit. Purchasers of common units in this offering will experience substantial and immediate dilution in net tangible book value per common unit for accounting purposes, as illustrated in the following table:

Assumed initial public offering price per common unit	$	$
Pro forma net tangible book value per unit before this offering[(1)]	$	$
Decrease in net tangible book value per unit attributable to purchasers in the offering		
Less: Pro forma net tangible book value per unit after this offering[(2)]		
Immediate dilution in tangible net book value per common unit to purchasers in the offering[(3)(4)]	$	$

(1) Determined by dividing the pro forma net tangible book value of our net assets immediately prior to the offering by the number of common units to be issued to the Founders and the general partner.

(2) Determined by dividing our pro forma as adjusted net tangible book value, after giving effect to the application of the net proceeds of this offering, by the total number of units to be outstanding after this offering (common units and general partner units).

(3) If the initial public offering price were to increase or decrease by $1.00 per common unit, then dilution in net tangible book value per common unit would equal $ and $, respectively.

(4) Because the total number of units outstanding following the consummation of this offering will be impacted by any exercise of the underwriters' option to purchase additional common units and any net proceeds from such exercise will be retained by us, there will be a change to the dilution in net tangible book value per common unit to purchasers in the offering due to any such exercise of the underwriters' option to purchase additional common units.

The following table sets forth the number of units that we will issue and the total consideration contributed to us by our general partner and its affiliates, including the Founders, and by the purchasers of common units in this offering upon the closing of the transactions contemplated by this prospectus:

	Units Acquired		Total Consideration	
	Number	Percent	Amount (in thousands)	Percent
General partner and affiliates(1)		%		%
Purchasers in the offering(2)		%		%
Total		100.0%		100.0%

(1) Upon the consummation of the transactions contemplated by this prospectus, and assuming the underwriters do not exercise their option to purchase additional common units, our general partner, its owners and their affiliates will own common units and non-economic general partner units.

(2) Total consideration is after deducting underwriting discounts and estimated offering expenses.

OUR CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with the factors and assumptions upon which our cash distribution policy is based, which are included under the heading "—Assumptions and Considerations" below. In addition, you should read "Forward-Looking Statements" and "Risk Factors" for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business.

General

Our Cash Distribution Policy

Our partnership agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects a basic judgment that our unitholders generally will be better served by us distributing our available cash, after expenses and reserves, rather than retaining it. Under our current cash distribution policy, initially we intend to make quarterly distributions on our common units of $ per unit, or $ per unit on an annualized basis, to the extent we have sufficient available cash after the establishment of cash reserves and the payment of costs and expenses, including the payment of expenses to our general partner. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions from our available cash in this or any other amount, and our general partner has considerable discretion to determine the amount of cash available for distribution each quarter. Generally, we define available cash as the sum of our (i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves, (ii) cash on hand on the date on which our general partner determines the amount of cash available for distribution, which we refer to as the date of determination, resulting from dividends or distributions received after the end of the quarter from equity interests in any person other than a subsidiary in respect of operations conducted by such person during the quarter, and (iii) if our general partner so determines, cash on hand at the date of determination resulting from working capital borrowings made after the end of the quarter. We may, but are under no obligation to, borrow funds to make quarterly distributions to unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long-term, but short-term factors have caused available cash from operations to be insufficient to pay the distribution at the current level. Because we are not subject to an entity-level federal income tax, we expect to have more cash to distribute to our unitholders than would be the case if we were subject to such federal income tax.

Because our policy will be to distribute all available cash we generate each quarter, without reserving cash for future distributions or borrowing to pay distributions during periods of low revenue, our unitholders will have direct exposure to fluctuations in the amount of cash generated by our business. Our quarterly cash distributions from our available cash, if any, will not be stable and will vary from quarter to quarter as a direct result of variations in the performance of our operators and revenue caused by fluctuations in the prices of oil and natural gas. Such variations may be significant.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy

Although our partnership agreement requires that we distribute all of our available cash quarterly, there is no guarantee that we will make quarterly cash distributions from our available cash to our unitholders at the level currently estimated or at all, and we have no legal obligation to do so. Our current cash distribution policy is subject to certain restrictions, as well as the considerable discretion of our general partner in determining the amount of our available cash each quarter. The following factors will affect our ability to make cash distributions, as well as the amount of any cash distributions we make:

- Our cash distribution policy may be subject to restrictions on distributions under our Credit Facility or other debt agreements that we may enter into in the future. Specifically, our Credit Facility contains financial tests and covenants that we must satisfy. These financial tests and covenants are described in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement." Should we be unable to satisfy these restrictions, or if a default occurs under our Credit Facility, we would be prohibited from making cash distributions to our unitholders notwithstanding our stated cash distribution policy. Any future indebtedness may contain similar or more stringent restrictions.

- The amount of cash that we distribute and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. Specifically, our general partner will have the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment of or increase in those reserves could result in a reduction in cash distributions from levels we currently anticipate pursuant to our stated cash distribution policy. Any decision to establish cash reserves made by our general partner in good faith will be binding on our unitholders. If our general partner does not set aside sufficient cash reserves or make sufficient cash expenditures to maintain the current production levels over the long-term of our oil and natural gas properties, we will be unable to pay any cash distributions from cash generated from operations. We are unlikely to be able to sustain our current level of distributions without making accretive acquisitions or capital expenditures that maintain the current production levels of our oil and natural gas properties. Decreases in commodity prices from current levels will adversely affect our ability to pay distributions. If our asset base decreases and we do not reduce our distributions, a portion of the distributions may have the effect of, and may effectively represent, a return of part of our unitholders' investment in us as opposed to a return on our unitholders' investment.

- Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates for all direct and indirect expenses they incur on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of cash available to pay cash distributions to our unitholders. Furthermore, immediately prior to the closing of this offering, we and our general partner will enter into a services agreement with the Services Company, pursuant to which the Services Company will provide management, administrative and operating services to us. Under the services agreement, we will reimburse the Services Company for certain allocable expenses. For more information, see "Certain Relationships and Related Party Transactions—Services Agreement."

- Although our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including the provisions requiring us to make cash distributions contained therein, may be amended. Our partnership agreement generally may be amended with the consent of our general partner and the approval of the holders of a majority of our outstanding common units (including common units held by affiliates of our general partner). At the closing of this offering, the Founders will control our general partner, and the Existing Owners (including the Founders) will own approximately % of our outstanding common units. Please read "The Partnership Agreement—Amendment of the Partnership Agreement."

- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner.

- Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets.

- We may lack sufficient cash to pay distributions to our unitholders due to a number of factors, including decreases in commodity prices, decreases in our oil and natural gas production or increases in our general and administrative expenses, principal and interest payments on our outstanding debt, tax expenses, working capital requirements or anticipated cash needs.

- We own a 50% interest in Cross Timbers, with the other 50% owned by the XTO entities. Pursuant to the JV LLCA, Cross Timbers is managed by us and governed by a member management committee comprised of six members, three of whom are appointed by us and three of whom are appointed by the XTO Entities. Cross Timbers is required to distribute all net cash flow to the members pro rata in accordance with their respective membership interests on a quarterly basis pursuant to the JV LLCA, with such net cash flow being calculated net of reserves for reasonable and prudent operations as determined by the majority of the management committee. Therefore, we do not have sole control of the amount of distributions to be made by Cross Timbers.

- If and to the extent our cash available for distribution materially declines, we may reduce our quarterly distribution in order to service or repay our debt or fund maintenance or growth capital expenditures.

- We will not have a minimum quarterly distribution. Furthermore, none of our limited partner interests, including those held by the Founders or Existing Owners, will be subordinate in right of distribution payment to the common units sold in this offering.

- Our general partner may reduce our distributions if action is taken by our general partner as described under "Our Partnership Agreement—Election to be treated as a Corporation" that results in our becoming taxable as a corporation or otherwise subject to taxation as an entity for federal income tax purposes. In such an event, the distribution levels may be reduced to account for any current and future estimated tax liabilities we would incur as a corporation. The distributions will also be proportionately adjusted in the event of any distribution, combination or subdivision of common units in accordance with the partnership agreement. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions."

Our Partnership Agreement Requires That We Distribute All of Our Available Cash, Which Could Limit Our Ability to Grow

Our partnership agreement requires us to distribute all of our available cash to our unitholders on a quarterly basis. As a result, our growth may not be as fast as businesses that reinvest all of their available cash to expand ongoing operations. Further, we may rely upon our cash reserves (including the net proceeds that we will retain from this offering) and external financing sources, including borrowings under our Credit Facility (under which no amounts will be outstanding at the closing of this offering) and the issuance of debt and equity securities, to fund future acquisitions and other expansion capital expenditures. Our management has collectively invested more than $500 million in us since our inception. Following the completion of this offering, we expect that we will not be able to rely on our management or our partners for capital and will need to utilize the public equity or debt markets and bank financings to fund acquisitions and capital expenditures. To the extent we require external sources of capital to fund our growth and are unable to access such sources, the requirement in our partnership agreement to distribute all of our available cash and our current cash distribution policy may impair our ability to grow. Our Credit Facility limits, and any future debt agreements may limit, our ability to incur additional debt, including through the issuance of debt securities. Please read "Risk Factors—Risks Related to Our Business—Our Credit Facility has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders." To the extent we issue additional units, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our cash distributions per unit. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to our common units, and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such additional units. If we incur additional debt to finance our growth strategy, we will have increased interest expense, which in turn will reduce the available cash that we have to distribute to our unitholders. Please read "Risk Factors—Risks Related to Our Business—Increases in interest rate could adversely impact our unit price and our ability to issue additional equity and incur debt."

Unaudited Pro Forma Cash Available for Distribution for the Year Ended December 31, 2021 and the Twelve Months Ended March 31, 2022

On a pro forma basis, assuming we had completed this offering on January 1, 2021, our cash available for distribution for the year ended December 31, 2021 and the twelve months ended March 31, 2022 would have been approximately $ million and $ million, respectively. This amount would have been sufficient to pay a cash distribution of $ per unit per quarter ($ on an annualized basis) during the year ended December 31, 2021, and a cash distribution of $ per unit per quarter ($ on an annualized basis) during the twelve-month period ended March 31, 2022.

Our unaudited pro forma cash available for distribution does not include incremental general and administrative expenses that we expect we will incur as a result of being a publicly traded partnership, consisting of costs associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, investor relations activities, Sarbanes-Oxley Act compliance, NYSE, registrar and transfer agent fees, incremental director and officer liability insurance costs and officer and director compensation. We estimate that these incremental general and administrative expenses initially will be approximately $ million per year. Such incremental general and administrative expenses are not reflected in our historical or pro forma financial statements. Our unaudited pro forma cash available for distribution does not include the Andrews Parker acquisition for the period prior to the acquisition, and only gives effect to the Andrews Parker acquisition for results from and after the date of acquisition, December 1, 2021.

The pro forma financial statements, from which pro forma cash available for distribution is derived, do not purport to present our results of operations had the transactions contemplated in this prospectus actually been completed as of the dates indicated. Furthermore, cash available for distribution is a cash accounting concept, while our unaudited pro forma financial statements have been prepared on an accrual basis. We derived the amounts of pro forma cash available for distribution stated above in the manner described in the table below. As a result, the amount of pro forma cash available for distribution should only be viewed as a general indication of the amount of cash available for distribution that we might have generated had we been formed and completed the transactions contemplated in this prospectus in earlier periods.

The following table illustrates, on an unaudited pro forma basis for the year ended December 31, 2021 and the twelve months ended March 31, 2022, the amount of available cash that would have been available for distribution to our unitholders, assuming in each case that this offering had been consummated on January 1, 2021.

TXO Energy Partners, L.P.
Unaudited Pro Forma Cash Available for Distribution

	Pro Forma	
	Year Ended December 31, 2021	Twelve Months Ended March 31, 2022
	(in thousands, except per unit data)	
Net income(1)		
Interest expense		
Interest income		
Depreciation, depletion and amortization		
Impairment expenses		
Accretion of discount on asset retirement obligations		
Exploration expense		
Non-cash derivative (gain) / loss		
Non-cash incentive compensation		
Non-cash (gain) on forgiveness of debt		
Other non-cash (gain) / loss		
Adjusted EBITDAX(2)		
Net Cash Provided by Operating Activities		
Development costs(3)		
Cash Available for Distribution (4)		
Pro Forma Annualized distributions per unit		
Pro Forma Estimated annual cash distributions (5):		
Distributions on common units held by purchasers in this offering		
Distributions on common units held by affiliates of our general partner		
Total estimated annual cash distributions		

(1) Includes the forecasted effect of cash settlements of commodity derivative instruments. This amount does not include unrealized commodity derivative gains (losses), as such amounts represent non-cash items and cannot be reasonably estimated in the forecast period.
(2) Adjusted EBITDAX is defined in "Prospectus Summary—Non-GAAP Financial Measures."

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(3) For purposes of the presentation of Unaudited Pro Forma Cash Available for Distribution, we have included estimated development costs for the twelve months ending June 30, 2023 of approximately $ million. We estimate that this amount of average development costs will enable us to maintain our current level of production from the oil and gas assets we own today through June 30, 2023, based on a forecasted production level of Boe per day for the twelve months ending June 30, 2023.

(4) Cash available for distribution is defined in “Prospectus Summary—Non-GAAP Financial Measures.”

Estimated Cash Available for Distribution for the Twelve Months Ending June 30, 2023

The financial forecast presents, to the best of our knowledge and belief, our expected results of operations, Adjusted EBITDAX and cash available for distribution for the twelve months ending June 30, 2023. Based upon the assumptions and considerations set forth in the table below, we estimate that we will generate $ in cash available for distribution for the twelve months ending June 30, 2023, which would be sufficient to pay cash distributions of $ per common unit· The number of outstanding common units on which we have based such belief does not include any common units that may be issued under the long-term incentive plan that our general partner is expected to adopt prior to the closing of this offering. Furthermore, the financial forecast assumes that we do not make any acquisitions of properties during the twelve months ending June 30, 2023 except as reflected in maintenance capital expenditures.

Our Statement of Estimated Adjusted EBITDAX reflects our judgment, as of the date of this prospectus, of conditions we expect to exist and the course of action we expect to take in order to be able to be able to generate cash available for distribution in the amount of $ per common unit, or $ million in the aggregate for the twelve months ending June 30, 2023. The assumptions discussed below under “—Assumptions and Considerations” are those that we believe are significant to our ability to generate the requisite Adjusted EBITDAX. Based on such assumptions, we believe our actual results of operations and cash flow will be sufficient to generate the Adjusted EBITDAX necessary to pay the forecasted aggregate annualized cash distribution. We can, however, give you no assurance that we will generate this amount. There will likely be differences between our estimated Adjusted EBITDAX and our actual results, and those differences could be material. If we fail to generate the estimated Adjusted EBITDAX contained in our forecast, our annualized cash distribution to all of our unitholders may be less than expected. We can give you no assurance that our assumptions will be realized or that we will generate any available cash, in which event we will not be able to pay quarterly cash distributions from our available cash on our common units.

While we do not as a matter of course make public projections as to future sales, earnings or other results, our management has prepared the prospective financial information that is the basis of our estimated Adjusted EBITDAX below to substantiate our belief that we will have sufficient cash to pay the forecasted cash distribution on all our common units for twelve months ending June 30, 2023. This forecast is a forward-looking statement and should be read together with our historical financial statements and the accompanying notes included elsewhere in this prospectus and “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” The accompanying prospective financial information was not prepared with a view toward complying with the published guidelines of the SEC or the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in the view of our management, is substantially consistent with those guidelines and was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management’s knowledge and belief, the assumptions and considerations on which we base our belief that we can generate Adjusted EBITDAX necessary for us to pay cash distribution on all of our outstanding common for the twelve months ending June 30, 2023 equal to $ per common unit. Readers of this prospectus are cautioned not to place undue reliance on this prospective financial information. Please read “—Assumptions and Considerations,” including the sensitivity analysis included therein.

The prospective financial information included in this prospectus has been prepared by, and is the responsibility of, our management. KPMG LLP has not compiled, examined or performed any procedures with respect to the accompanying prospective financial information and, accordingly, KPMG LLP does not express an opinion or any other form of assurance with respect thereto. The KPMG LLP reports included in the registration statement relate to our historical financial information. It does not extend to the prospective financial information and should not be read to do so.

When considering our financial forecast, you should keep in mind the risk factors and other cautionary statements under "Risk Factors." Any of the risks discussed in this prospectus, to the extent they are realized, could cause our actual results of operations to vary significantly from those that would enable us to generate Adjusted EBITDAX necessary to pay the forecasted aggregate annualized cash distribution on all of our outstanding common units for the twelve months ending June 30, 2023.

We are providing the Statement of Estimated Adjusted EBITDAX to supplement our historical financial statements and in support of our belief that we will have sufficient available cash to pay the forecasted aggregate annualized cash distribution on all of our outstanding common units for the twelve months ending June 30, 2023. Please read below under "—Assumptions and Considerations" for further information about the assumptions we have made for the financial forecast.

We do not undertake any obligation to release publicly the results of any future revisions we may make to this prospective financial information or to update this prospective financial information to reflect events or circumstances after the date of this prospectus. Therefore, you are cautioned not to place undue reliance on this information.

Our Estimated Cash Available for Distribution

The following table shows how we calculate estimated available cash for the twelve months ending June 30, 2023 and for each quarter during that twelve-month period that would be available for distribution to our unitholders. All of the amounts for the twelve months ending June 30, 2023 in the table below are estimates. The assumptions that we believe are relevant to particular line items in the table below are explained in the corresponding footnotes and in "—Assumptions and Considerations."

Neither our independent registered public accounting firm nor any other independent registered public accounting firm has compiled, examined or performed any procedures with respect to the forecasted financial information contained herein, nor has it expressed any opinion or given any other form of assurance on such information or its achievability, and it assumes no responsibility for such forecasted financial information. Our independent registered public accounting firm's reports included elsewhere in this prospectus relate to our audited historical financial statements. These reports do not extend to the table and the related forecasted information contained in this section and should not be read to do so.

	Three Months Ending September 30, 2022	Three Months Ending December 31, 2022	Three Months Ending March 31, 2023	Three Months Ending June 30, 2023	Twelve Months Ending June 30, 2023
	(in thousands, except per unit data) (unaudited)				
Net Income					
Interest expense					
Interest income					
Depreciation, depletion and amortization					
Impairment expenses					
Accretion of discount on asset retirement obligations					
Exploration expense					
Non-cash derivative (gain) / loss					
Non-cash incentive compensation					
Non-cash (gain) on forgiveness of debt					
Other non-cash (gain) / loss					
Impairment expenses					
Estimated Adjusted EBITDAX(2)					
Net Cash Provided by Operating Activities					
Development costs(3)					
Cash Available for Distribution (4)					
Annualized Cash distribution per unit					
Estimated annual cash distributions(5):					
Distributions on common units held by purchasers in this offering ( )					
Distributions on common units held by affiliates of our general partner ( )					
Total estimated annual cash distributions					

(1) Includes the forecasted effect of cash settlements of commodity derivative instruments. This amount does not include unrealized commodity derivative gains (losses), as such amounts represent non-cash items and cannot be reasonably estimated in the forecast period.

(2) Adjusted EBITDAX is defined in “Prospectus Summary—Non-GAAP Financial Measures.”

(3) In calculating the estimated cash available for distribution, we have included estimated development costs for the twelve months ending June 30, 2023 of approximately $ million. We estimate that this amount of average development costs will enable us to maintain our current level of production from the oil and gas assets we own today through June 30, 2023, based on a forecasted production level of Boe per day for the twelve months ending June 30, 2023.

(4) Cash available for distribution is defined in “Prospectus Summary—Non-GAAP Financial Measures.”

(5) The number of outstanding common units assumed herein does not include any common units that may be issued under the long-term incentive plan that our general partner is expected to adopt prior to the closing of this offering.

Assumptions and Considerations

Based upon the specific assumptions outlined below, we expect to generate Cash available for distribution for the twelve months ending June 30, 2023 of approximately $ million.

While we believe that these assumptions are reasonable in light of management's current expectations concerning future events, the estimates underlying these assumptions are inherently uncertain and are subject to significant business, economic, regulatory, environmental and competitive risks and uncertainties that could cause actual results to differ materially from those we anticipate. If our assumptions are not correct, the amount of actual cash available to pay distributions could be substantially less than the amount we currently estimate, in which event the market price of our common units may decline substantially. When reading this section, you should keep in mind the risk factors and other cautionary statements described under "Risk Factors" and "Forward-Looking Statements." Any of the risks discussed in this prospectus could cause our actual results to vary significantly from our estimates.

Operations and Revenue

Production. Our ability to generate sufficient cash from operations to pay cash distributions to unitholders is a function of two primary variables: (i) production volumes and (ii) commodity prices. Production volumes directly impact our revenue. Any negative effect on production volumes could have a material adverse effect on our business, financial condition, results of operations and cash available for distribution. Our existing production will naturally decline over time as the applicable reservoir is depleted. As of December 31, 2021, our decline rate for our oil and gas properties over the next twelve months in the Permian and San Juan basins, are approximately 7% and 10%, respectively.

The following table presents historical production volumes for our properties on a pro forma basis for the Chevron Vacuum Acquisition for the year ended December 31, 2021 and the twelve months ended March 31, 2022 and on a forecasted basis for the twelve months ending June 30, 2023:

	Pro Forma Year Ended December 31, 2021	Pro Forma Twelve Months Ended March 31, 2022	Forecasted Twelve Months Ending June 30, 2023
Annual production:			
Oil and condensate (MBbl)			
Natural gas liquids (MBbl)			
Natural gas (MMcf)			
Total (MBoe)			
Average net daily production:			
Oil and condensate (MBbl)			
Natural gas liquids (MBbl)			
Natural gas (MMcf)			
Total (Boe/d)			

We estimate that our total oil and natural gas production for twelve months ending June 30, 2023 will be Boe per day as compared to Boe per day on a pro forma basis for the year ended December 31, 2021 and Boe per day on a pro forma basis for the twelve months ended March 31, 2022. For the month ended March 31, 2022, our average net production was Boe per day. We expect to spend $ million on these activities in the second half of 2022. We intend to maintain our forecasted production level of Boe per day for the twelve months ending June 30, 2023 with cash generated from operations.

Prices. Our results of operations depend on many factors, particularly the price of our commodity production and our ability to market our production effectively. Oil and natural gas prices have historically been volatile and currently are at record or near record-high levels. During the period from January 1, 2021 through June 30, 2022, prices for crude oil and natural gas reached a high of $123.70 per Bbl and $23.86 per MMBtu, respectively, and a low of $47.62 per Bbl and $2.43 per MMBtu, respectively. A future decline in commodity prices may adversely affect our business, financial condition or results of operations. Lower commodity prices may not only decrease our revenues, but also the amount of oil and natural gas that we can produce economically. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our Credit Facility, which is redetermined semi-annually.

The NYMEX WTI, for oil prices, and NYMEX Henry Hub, for gas prices, are widely used benchmarks for the pricing of oil and natural gas in the United States. The price we receive for our oil and natural gas production is generally different than the NYMEX price because of adjustments for delivery location ("*basis*"), relative quality and other factors. The differentials to published oil and natural gas prices are based upon our analysis of the historic price differentials for production from the mineral interests with consideration given to gravity, quality and transportation and marketing costs that may affect these differentials. There is no assurance that these assumed differentials will occur. The table below illustrates the relationship between average oil, natural gas and natural gas liquids realized sales prices and average NYMEX futures prices as of June 30, 2022 on a pro forma basis for the year ended December 31, 2021 and the twelve months ended March 31, 2022 and our forecast for the twelve months ending June 30, 2023:

	Pro Forma Year Ended December 31, 2021	Pro Forma Twelve Months Ended March 31, 2022	Forecasted Twelve Months Ending June 30, 2023
Average oil sales prices (Bbl):			
Average daily NYMEX-WTI oil price			
Differential to NYMEX-WTI oil			
Realized oil sales price (excluding derivatives)			
Realized oil sales price (including derivatives)			
Average natural gas liquids sales prices (Bbl):			
Average daily NYMEX-WTI oil price			
Differential to NYMEX-WTI oil price			
Realized natural gas liquids sales price (excluding derivatives)			
Realized natural gas liquids sales price (including derivatives)			
Average natural gas sales prices (Mcf):			
Average daily NYMEX-Henry Hub natural gas price			
Differential to NYMEX-Henry Hub natural gas			
Realized natural gas sales price (excluding derivatives)			
Realized natural gas sales price (including derivatives)			

Hedging Activities. We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations and to satisfy the requirement under our Credit Facility to hedge at least (a) 75% of reasonably anticipated projected production of proved developed producing reserves for the 12-month period following January 1, 2022 and (b) thereafter 50% of reasonably anticipated projected production of proved developed producing reserves for the 30-month period following the date of any hedging transaction. However, as of any time, if the net leverage ratio (the ratio of total net debt-to-EBITDAX) is less than or equal to 1.0 to 1.0 and the cash and cash equivalents on hand are equal to or greater than 20% of the borrowing base then in effect, the minimum required hedge volume for month one through month 24 will be reduced to 50%. Our Credit Facility prohibits us from hedging more than 90% of our reasonably projected production for any fiscal year. See Management's Discussion and Analysis of Financial Condition and Results of Operations—

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Liquidity and Capital Resources—Revolving credit agreement" for more information. Our policy is to consider hedging a portion of our production at commodity prices management deems attractive.

As of the date of this prospectus, our commodity derivative contracts will cover MBbl, or approximately %, of our forecasted total oil production of MBbl, MBbl, or approximately %, of our forecasted total natural gas liquid production of MBbl, and Mcf, or approximately %, of our forecasted total natural gas production of Mcf, for the twelve months ending June 30, 2023. Our commodity derivative contracts consist of swap and collar agreements based upon NYMEX-WTI prices. The table below shows the volumes and prices covered by the commodity derivative contracts for the twelve months ending June 30, 2023. For purposes of our forecast, we have assumed that we will not enter into additional natural gas or oil derivative contracts during the forecast period, although we may do so on an opportunistic basis if market conditions are favorable. See "Risk Factors—We use derivative instruments to economically hedge exposure to changes in commodity price and, as a result, are exposed to credit risk and market risk."

	Swaps		Collars		
	Bbl	Weighted Average Price	Bbl	Weighted Average Floor Price	Weighted Average Ceiling Price
Oil:					
June 2022—June 2023					
% of forecasted oil production					
Natural Gas Liquids:					
June 2022—June 2023					
% of forecasted natural gas liquids production					
Natural Gas:					
June 2022—June 2023					
% of forecasted natural gas production					

Operating Revenues and Realized Commodity Derivative Gains. The following table illustrates the primary components of operating revenues and realized commodity derivative gains on a pro forma basis for the year ended December 31, 2021 and the twelve months ended March 31, 2022 and on a forecasted basis for the twelve months ending June 30, 2023:

	Pro Forma Year Ended December 31, 2021	Pro Forma Twelve Months Ended March 31, 2022	Forecasted Twelve Months Ending June 30, 2023
		(in thousands)	
Oil:			
Oil revenues (excluding the effects of derivative instruments)			
Realized oil derivative instruments gain (loss)			
Total			
Natural gas liquids:			
Natural gas liquids revenue (excluding the effects of derivative instruments)			
Realized natural gas liquids derivative instruments gain (loss)			
Total			
Natural gas:			
Natural gas revenues (excluding the effects of derivative instruments)			
Realized natural gas derivative instruments gain (loss)			
Total			
Total:			
Operating revenues			
Commodity derivative instruments gain (loss)			
Operating revenue and realized commodity derivative instruments gains			

Expenses

Development Costs. Our estimated development costs for the twelve months ending June 30, 2023 of $ million represent our estimate of the average annual capital expenditures necessary to maintain our production through June 30, 2026 based on the forecasted production level of Boe per day for the twelve months ending June 30, 2023.

Production Expenses. The following table summarizes production expenses on an aggregate basis and on a per Boe basis for the year ended December 31, 2021, pro forma, the twelve months ended March 31, 2022, pro forma, and on a forecasted basis for the twelve months ending June 30, 2023:

	Pro Forma Year Ended December 31, 2021	Pro Forma Twelve Months Ended March 31, 2022	Forecasted Twelve Months Ended June 30, 2023
Production expenses (in thousands)			
Production expenses (per Boe)			

We estimate that our production expenses for the twelve months ending June 30, 2023 will be approximately $ million. Production expenses consist of lease operating expenses incurred for the operation and maintenance of wells and related equipment. On a pro forma basis, for the year ended December 31, 2021 and the twelve months ended March 31, 2022, production expenses were $ million and $ million, respectively.

Taxes, transportation and other. Taxes, transportation, and other expenses consist primarily of gathering fees and processing fees, transportation costs, severance taxes, and ad valorem taxes. Gathering, processing and transportation costs are recognized when control of the natural gas we sell occurs at the tailgate of the processing plant. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from production sold at fixed rates established by state or local taxing authorities. In general, the severance taxes we pay correlate to the changes in oil and natural gas revenues. We are also subject to ad valorem taxes in the counties where our production is located. We evaluate taxes, transportation, and other expense on a per Boe basis to monitor costs to ensure that they are at acceptable levels. Taxes, transportation, and other expenses can also be influenced by acquisitions, commodity prices, changes in values of our properties, sales mix and acquisitions.

The following table summarizes taxes, transportation and other on a pro forma basis for the year ended December 31, 2021, the twelve months ended March 31, 2022 and on a forecasted basis for the twelve months ending June 30, 2023:

	Pro Forma Year Ended December 31, 2021	Pro Forma Twelve Months Ended March 31, 2022	Forecasted Twelve Months Ended June 30, 2023
Oil and natural gas revenues, excluding the effect of Taxes, transportation and other (in thousands)			
Taxes, transportation and other (per Boe)			

General and Administrative Expenses. General and administrative expenses consist primarily of personnel related costs and are partially offset by certain reimbursements of overhead expenses, including Texas gross margin taxes. In connection with the consummation of this offering, we expect to incur additional costs related to being a public company. However, we do not expect to experience a material change in our cash cost structure, except as may be affected by our recent property acquisitions, the volatility of commodity prices, increased expenses as a publicly traded limited partnership, the effectives of our commodity derivative contracts, the effects of impairment on our producing properties. See “Management’s Discussion and Analysis of Financial Condition and Results of Operation—Factors Affecting the Comparability of Our Financial Condition and Results of Operations.”

Interest Expense. Interest expense is primarily a result of interest on our borrowings on our Credit Facility to fund operations and acquisitions of properties as well as the amortization of debt issuance costs associated with these borrowings. Interest expense can fluctuate with our level of indebtedness as well as changes in interest rates and includes commitment fees under our Credit Facility. We do not expect to have any indebtedness at the closing of this offering or during the twelve months ended June 30, 2023. Based on these assumptions, we estimate that our cash interest expense for the twelve months ending June 30, 2023 will be $ million as compared to $ million on a pro forma basis for both the year ended December 31, 2021 and the twelve months ended March 31, 2022.

Our Credit Facility requires us 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 3.00 to 1.00. For purposes of our current ratio covenant, "current assets" is deemed to include availability under the Credit Facility but excludes the unrealized gain (loss) of derivative instruments. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement" for additional detail regarding the covenants and restrictive provisions included in our Credit Facility.

Regulatory, Industry and Economic Factors

Our forecast for the twelve months ending June 30, 2023 is based on the following significant assumptions related to regulatory, industry and economic factors:

- There will not be any new federal, state or local regulation of portions of the energy industry in which we operate, or any interpretation of existing regulations, that will be materially adverse to our business;
- There will not be any material nonperformance or credit-related defaults by suppliers, customers or vendors, or shortage of skilled labor;
- All supplies and commodities necessary for production and sufficient transportation will be readily available;
- There will not be any major adverse change in commodity prices or the energy industry in general;
- There will not be any material accidents, releases, weather-related incidents, unscheduled downtime or similar unanticipated events, including any events that could lead to force majeure under any of our marketing agreements;
- There will not be any adverse change in the markets in which we operate resulting from supply or production disruptions, reduced demand for our product or significant changes in the market prices for our product; and
- Market, insurance, regulatory and overall economic conditions will not change substantially.

Sensitivity Analysis

Our ability to generate sufficient cash from operations to pay cash distributions to our unitholders is a function of two primary variables: (i) production volumes; and (ii) commodity prices. In the tables below, we illustrate the effect that changes in either of these variables, while holding all other variables constant, would have on our ability to generate sufficient cash from our operations to pay the forecasted cash distributions on our outstanding common units for the twelve months ending June 30, 2023.

We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impracticable to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome.

Production Volume Changes

Production volumes directly impact our revenue. Any negative effect on production volumes could have a material adverse effect on our business, financial condition, results of operations and cash available for distribution. The following table shows estimated Adjusted EBITDAX under production levels of 90%, 100% and 110% of the production level we have forecasted for the twelve months ending June 30, 2023. The estimated Adjusted EBITDAX amounts shown below are based on the assumptions used in our forecast.

	Percentage of Forecasted Net Production		
	90%	100%	110%
	(in thousands, except per unit amounts)		
Forecasted net production:			
Oil (MBbl)			
Natural gas (MMcf)			
Natural gas liquids (MBbl)			
Total (MBoe)			
Oil (Bbl/d)			
Natural gas (Mcf/d)			
Natural gas liquids (Bbl/d)			
Total (Boe/d)			
Forecasted prices:			
NYMEX-WTI oil price (per Bbl)			
Realized oil price (per Bbl) (excluding derivatives)			
Realized oil price (per Bbl) (including derivatives)			
NYMEX-WTI natural gas liquids price (per Bbl)			
Realized natural gas liquids price (per Bbl) (excluding derivatives)			
Realized natural gas liquids price (per Bbl) (including derivatives)			
NYMEX-Henry Hub natural gas price (per Mcf)			
Realized natural gas price (per Mcf) (including derivatives)			
Realized natural gas price (per Mcf) (excluding derivatives)			
Forecasted Cash Available for Distribution:			
Adjusted EBITDAX:			
Net Income(1)			
Interest expense			
Interest income			
Depreciation, depletion and amortization			

	Percentage of Forecasted Net Production		
	90%	100%	110%
	(in thousands, except per unit amounts)		
Impairment expenses			
Accretion of discount on asset retirement obligations			
Exploration expense			
Non-cash derivative (gain) / loss			
Non-cash incentive compensation			
Non-cash (gain) on forgiveness of debt			
Other non-cash (gain) / loss			
Estimated Adjusted EBITDAX(2)			
Net Cash Provided by Operating Activities			
Development costs(3)			
Cash Available for Distribution(4)			

(1) Includes the forecasted effect of cash settlements of commodity derivative instruments. This amount does not include unrealized commodity derivative gains (losses), as such amounts represent non-cash items and cannot be reasonably estimated in the forecast period.

(2) Adjusted EBITDAX is defined in "Prospectus Summary—Non-GAAP Financial Measures."

(3) In calculating the estimated cash available for distribution, we have included development costs for the twelve months ending June 30, 2023 of approximately $ million. We estimate that this amount of average development costs will enable us to maintain our current level of production from the oil and gas assets we own today through June 30, 2023, based on a forecasted production level of Boe per day for the twelve months ending June 30, 2023.

(4) Cash available for distribution is defined in "Prospectus Summary—Non-GAAP Financial Measures."

As reservoir pressures decline, production from a given well or formation decreases. Maintaining or growing our future production and reserves will depend on our ability to continue to replace current production with new reserves. Accordingly, we plan to focus on maintaining reserves through both the drill bit and acquisitions, while maintaining a conservative financial profile. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel, and successfully identify and consummate acquisitions. See "Risk Factors—Risks Related to Our Business and the Oil, Natural Gas and NGL Industry" for a discussion of these and other risks affecting our proved reserves and production.

Commodity Price Changes

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

To reduce the impact of fluctuations in oil, NGL and natural gas prices on our revenues, we periodically enter into commodity derivative contracts with respect to certain of our oil, NGL and natural gas production through various transactions that limit the risks of fluctuations of future prices. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling. While there is a risk we may not be able to realize the full benefits of rising prices, these hedging activities are intended to limit our exposure to product price volatility and to maintain stable cash flows.

The following table shows estimated Adjusted EBITDAX under various assumed NYMEX-WTI oil and NYMEX-Henry Hub natural gas prices for the twelve months ending June 30, 2023. For the twelve months ending June 30, 2023, we have assumed that commodity derivative contracts will cover (i) MBoe, or approximately % of our estimated total oil production from proved reserves for the twelve months ending June 30, 2023, at a weighted average floor price of $ per Bbl, (ii) MBoe, or approximately % of our estimated total natural gas liquids production from proved reserves for the twelve months ending June 30, 2023, at a weighted average floor price of $ per Bbl and (iii) Mcf, or approximately % of our estimated total natural gas production from proved reserves for the twelve months ending June 30, 2023, at a weighted average floor price of $ per Mcf. In addition, the estimated Adjusted EBITDAX amounts shown below are based on forecasted realized commodity prices that take into account assumptions based on our average historical NYMEX commodity price differentials as set forth in our December 31, 2021 reserve report. We have assumed no changes in our production based on changes in prices. The estimated Adjusted EBITDAX amounts shown below are based on forecasted realized commodity prices that take into account our average NYMEX commodity price differential assumptions.

	Percentage of Forecasted Prices		
	90%	100%	110%
	(in thousands, except per unit amounts)		
NYMEX-WTI oil price (per Bbl):			
NYMEX-Henry Hub natural gas price (per MMBtu):			
Forecasted net production:			
Oil and condensate (MBbl)			
Natural gas liquids (MMcf)			
Natural gas (MMcf)			
Total (MBoe)			
Oil and condensate (Bbl/d)			
Natural gas liquids (MMcf)			
Natural gas (Mcf/d)			
Total (Boe/d)			
Forecasted prices:			
NYMEX-WTI oil price (per Bbl)			
Realized oil price (per Bbl) (excluding derivatives)			
Realized oil price (per Bbl) (including derivatives)			
NYMEX-WTI oil price (per Bbl)			
Realized natural gas liquids price (per Mcf) (excluding derivatives)			
Realized natural gas liquids price (per Mcf) (including derivatives)			
NYMEX-Henry Hub natural gas price (per MMBtu)			
Realized natural gas price (per Mcf) (excluding derivatives)			
Realized natural gas price (per Mcf) (including derivatives)			

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	Percentage of Forecasted Prices		
	90%	100%	110%
	(in thousands, except per unit amounts)		
Forecasted Adjusted EBITDAX projection:			
Forecasted Cash Available for Distribution:			
Adjusted EBITDAEX:			
Net Income(1)			
Interest expense			
Interest income			
Depreciation, depletion and amortization			
Impairment expenses			
Accretion of discount on asset retirement obligations			
Exploration expense			
Non-cash derivative (gain) / loss			
Non-cash incentive compensation			
Non-cash (gain) on forgiveness of debt			
Other non-cash (gain) / loss			
Estimated Adjusted EBITDAX(2)			
Net Cash Provided by Operating Activities			
Development costs(3)			
Cash Available for Distribution(4)			

(1) Includes the forecasted effect of cash settlements of commodity derivative instruments. This amount does not include unrealized commodity derivative gains (losses), as such amounts represent non-cash items and cannot be reasonably estimated in the forecast period.

(2) Adjusted EBITDAX is defined in "Prospectus Summary—Non-GAAP Financial Measures."

(3) In calculating the estimated cash available for distribution, we have included development costs for the twelve months ending June 30, 2023 of approximately $ million. We estimate that this amount of average development costs will enable us to maintain our current level of production from the oil and gas assets we own today through June 30, 2023, based on a forecasted production level of Boe per day for the twelve months ending June 30, 2023.

(4) Cash available for distribution is defined in "Prospectus Summary—Non-GAAP Financial Measures."

If NYMEX oil, natural gas liquids and natural gas prices decline, our estimated Adjusted EBITDAX would not decline proportionately for two reasons: (1) the effects of our commodity derivative contracts; and (2) production taxes, which are calculated as a percentage of our oil, natural gas liquids and natural gas revenues, excluding the effects of our commodity derivative contracts, and which decrease as commodity prices decline. Furthermore, we have assumed no decline in estimated production or oil, natural gas liquids and natural gas operating costs during the twelve months ending June 30, 2023. However, over the long-term, a sustained decline in prices would likely lead to a decline in production and operating costs, as well as a reduction in our realized oil, natural gas liquids and natural gas prices. Therefore, the foregoing table is not illustrative of all of the potential effects of changes in commodity prices for periods subsequent to June 30, 2023.

PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO CASH DISTRIBUTIONS

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

Distributions of Available Cash

General

Our partnership agreement requires that, within 60 days after the end of each quarter (other than the fourth quarter) and within 90 days after the end of the fourth quarter, beginning with the quarter ending , we distribute all of our available cash to unitholders of record on the applicable record date. We will adjust the amount of our cash distribution for the period from the closing of this offering through , based on the actual length of that period.

Definition of Available Cash

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- *less*, the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to our unitholders (including our general partner) for any one or more of the next four quarters;
- *plus*, all cash on hand on the date of determination resulting from dividends or distributions received after the end of the quarter from equity interests in any person other than a subsidiary in respect of operations conducted by such person during the quarter;
- *plus*, if our general partner so determines, all or a portion of cash on hand on the date of determination resulting from working capital borrowings made after the end of the quarter.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to unitholders. Working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within twelve months from sources other than additional working capital borrowings.

Methods of Distribution

We intend to distribute available cash to our unitholders, pro rata. Our partnership agreement permits, but does not require, us to borrow to pay distributions. Accordingly, there is no guarantee that we will pay any distribution on the units in any quarter.

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner may in the future acquire common units or other equity interests in us and will be entitled to receive distributions on any such interests.

Distributions of Cash Upon Liquidation

If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to our unitholders, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

SELECTED HISTORICAL AND PRO FORMA FINANCIAL DATA

The selected historical consolidated financial data set forth below as of and for each of the years ended December 31, 2021 and 2020 have been derived from our audited consolidated financial statements included elsewhere in this prospectus. The selected historical consolidated financial data set forth below as of March 31, 2022 and for the three months ended March 31, 2022 and 2021 are derived from our unaudited financial statements and related notes included elsewhere in this prospectus.

The selected unaudited pro forma financial data as of March 31, 2022 and for the three months ended March 31, 2022 and the year ended December 31, 2021 are derived from the unaudited pro forma condensed financial statements of TXO Energy Partners included elsewhere in this prospectus. Our unaudited pro forma condensed financial statements give pro forma effect to the following:

- the acquisition of producing properties and a gas processing plant in the Permian Basin in New Mexico and CO_2 assets in Colorado from Chevron in November 2021; and

- the issuance and sale by us to the public of common units in this offering and the application of the net proceeds as described in "Use of Proceeds."

The unaudited pro forma financial data were prepared as if the items listed above occurred on January 1, 2021, in the case of statement of operations data, or December 31, 2021, in the case of balance sheet data. We have not given pro forma effect to the Chevron Andrews Parker Acquisition or to the incremental general and administrative expenses that we expect to incur annually as a result of being a publicly traded partnership.

The unaudited pro forma historical financial data are presented for illustrative purposes only and are not necessarily indicative of the financial position that would have existed or the financial results that would have occurred if this offering and the Chevron Vacuum Acquisition had been consummated on the dates indicated, nor are they necessarily indicative of the financial position or results of our operations in the future. The pro forma adjustments, as described in the notes to the unaudited pro forma condensed combined financial statements, are preliminary and based upon currently available information and certain assumptions that our management believes are reasonable. The selected historical consolidated financial data are qualified in their entirety by, and should be read in conjunction with, the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section included in this prospectus and the consolidated financial statements and related notes and other financial information included in this prospectus. Among other things, those historical financial statements and unaudited pro forma condensed financial statements include more detailed information regarding the basis of presentation for the following information. Historical results are not necessarily indicative of results that may be expected for any future period.

You should read the following table in conjunction with "Use of Proceeds," "Management's Discussion and Analysis of Financial Condition and Results of Operations," our historical combined financial statements and our unaudited pro forma condensed financial statements and the notes thereto included elsewhere in this prospectus. Among other things, those historical financial statements and unaudited pro forma condensed financial statements include more detailed information regarding the basis of presentation for the following information.

	TXO Energy Partners Historical				TXO Energy Partners Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31	Three Months Ended March 31,
	2021	2020	2022	2021	2021	2022
	(unaudited) (in thousands)					
Statement of Operations Data:						
Revenues:						
Oil and condensate	$ 69,971	$ 59,070	$ (2,530)	$ 10,875		
Natural gas liquids	$ 27,875	$ 8,660	$ 3,121	$ 4,777		
Natural gas	$ 130,498	$ 41,034	$ (10,129)	$ 31,975		
Total revenues(1)	$ 228,344	$ 108,764	$ (9,538)	$ 47,627		
Expenses:						
Production	$ 69,256	$ 49,146	$ 25,026	$ 14,316		
Exploration	$ 124	$ 55	$ 87	$ 44		
Taxes, transportation and other	$ 58,040	$ 27,509	$ 23,487	$ 12,704		
Depreciation, depletion and amortization	$ 39,889	$ 42,322	$ 9,780	$ 9,245		
Impairment	$ —	$ 134,097	$ —	$ —		
Accretion of discount on asset retirement obligations	$ 4,670	$ 3,940	$ 1,477	$ 1,320		
General and administrative	$ 12,175	$ 6,995	$ 396	$ (89)		
Total expenses	$ 184,154	$ 264,064	$ 60,253	$ 37,540		
Operating income (loss)	$ 44,190	$ (155,300)	$ (69,791)	$ 10,087		
Other income (expenses):						
Other income	$ 14,139	$ 72	$ 5,872	$ 15		
Interest income	$ 16	$ 194	$ 6	$ 3		
Interest expense	$ (5,870)	$ (8,204)	$ (1,670)	$ (1,365)		
Total other income (expenses)	$ 8,285	$ (7,938)	$ 4,208	$ (1,347)		
Net income (loss)	$ 52,475	$ (163,238)	$ (65,583)	$ 8,740		
Net income per limited partner unit (basic and diluted)						

	TXO Energy Partners Historical				TXO Energy Partners Pro Forma	
	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31	Three Months Ended March 31,
	2021	2020	2022	2021	2021	2022
			(unaudited) (in thousands)			
Weighted average number of limited partner units outstanding (basic and diluted)						
Other Financial Data:						
Adjusted EBITDAX	$ 85,348	$ 32,322	$ 38,778	$ 20,711		
Cash Available for Distribution	$ 72,348	$ 20,132	$ 36,499	$ 18,037		
Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 73,726	$ 18,964	$ 28,665	$ 21,859		
Investing activities	$(227,801)	$ (16,718)	$ (5,792)	$ (1,492)		
Financing activities	$ 139,689	$ 14,067	$ (15,064)	$ (20,004)		
Balance Sheet Data (at period end):						
Total assets	$ 832,820	$623,940	$840,633	$615,607		
Total long-term debt	$ 152,100	$151,252	$137,100	$131,252		
Partners' capital	$ 541,359	$303,268	$475,776	$311,660		

(1) Includes the effect of unrealized losses on commodity derivatives.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our audited financial statements as of and for the years ended December 31, 2020 and 2021 and the three months ended March 31, 2022, and related notes thereto, included elsewhere in this prospectus. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. These forward-looking statements are dependent upon events, risks and uncertainties that may be outside of our control. Our actual results could differ materially from those disclosed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this prospectus, particularly in "Risk Factors" and "Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Unless otherwise indicated, throughout this discussion the term "MBoe" refers to thousands of barrels of oil equivalent quantities produced for the indicated period, with natural gas and NGL quantities converted to Bbl on an energy equivalent ratio of six Mcf to one barrel of oil.

Overview

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

As significant owners of the Company, our management has sought to build a business that can generate substantial free cash flow and make relatively consistent distributions to our unitholders. We have grown the business steadily through thoughtful acquisitions and the disciplined development of our assets. We believe we have a proven track record of responsible capital stewardship and risk mitigation. We strive to make every investment—whether acquiring additional assets or the development of our existing portfolio—with the goal of maintaining and, over time, modestly increasing cash flows to drive increased distributions to our unitholders.

We seek to maintain a flat to low growth production profile through a combination oflow-risk development and exploitation of our existing properties, which is generally funded by cash flow from operating activities, and acquisitions of primarily producing properties. To date we have been successful in offsetting the natural decline in production from reservoir depletion through acquisitions and drilling, adding more reserves than we produce. Funding sources for our acquisitions have included proceeds from bank borrowings, cash from our partners and cash flow from operating activities. Our development budget is approximately $30.0 million for 2022 (of which $ 0.7 million has been incurred as of March 31, 2022) and approximately $30.0 million for 2023.

Market Outlook

The oil and natural gas industry is cyclical and commodity prices are highly volatile. During the period from January 1, 2021 through June 30, 2022, prices for crude oil and natural gas reached a high of $123.70 per Bbl and $23.86 per MMBtu, respectively, and a low of $47.62 per Bbl and $2.43 per MMBtu, respectively. Oil prices steadily increased through 2021 due to continued recovery in demand before increasing drastically in the first half of 2022 due to further demand, domestic supply reductions, OPEC control measures and market disruptions resulting from the Russia-Ukraine war and sanctions on Russia. Since the Russia-Ukraine conflict first commenced, WTI crude oil prices have trended higher, rising from $92.81 per Bbl on February 24, 2022 to a high of $123.70 per Bbl in March 2022 and $104.79 per Bbl as of July 8, 2022. These prices have been very volatile and experience large swings, sometimes on a day-to-day or week-to-week basis.

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

Although inflation in the United States had been relatively low for many years, there was a significant increase in inflation beginning in the second half of 2021, which has continued into 2022, due to a substantial increase in the money supply, a stimulative fiscal policy, a significant rebound in consumer demand as COVID-19 restrictions were relaxed, the Russia-Ukraine war and worldwide supply chain disruptions resulting from the economic contraction caused by COVID-19 and lockdowns followed by a rapid recovery. Inflation rose from 5.4% in June 2021 to 5.8% in December 2021 to 8.6% in May 2022. Global, industry-wide supply chain disruptions have resulted in widespread shortages of labor, materials and services. Such shortages have resulted in our facing significant cost increases for labor, materials and services. We do not expect these shortages and cost increases to reverse in the short term. Typically, as prices for oil and natural gas increase, so do associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion to prices. We cannot predict the future inflation rate but to the extent inflation remains elevated, we may experience further cost increases in our operations, including costs for drill rigs, workover rigs, tubulars and other well equipment, as well as increased labor costs. If we are unable to recover higher costs through higher commodity prices, our current revenue stream, estimates of future reserves, borrowing base calculations, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions would all be significantly impacted.

Sources of Our Revenue

Our revenues are derived from the sale of our oil, NGLs and natural gas production. Our revenues are influenced by production volumes and realized prices on the sale of oil, NGLs, and natural gas including the effect of our commodity derivative contracts. We sell oil, natural gas and NGLs at a specific delivery point, pay transportation to third parties and receive proceeds from the purchaser with no transportation deduction. As a result, we record transportation costs we pay to third parties as taxes, transportation and other deductions. Pricing of commodities is subject to supply and demand as well as to seasonal, political and other conditions that we generally cannot control. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. The following table presents the breakdown of our revenues including both the realized and unrealized effects of our commodity derivative contracts for the periods specified below:

	For the Year Ended December 31,		For the Three Months Ended March 31,	
	2021	2020	2022	2021
Crude oil sales	31%	54%	27%	23%
Natural gas sales	57%	38%	106%	67%
Natural gas liquid sales(1)	12%	8%	(33)%	10%

(1) NGL sales reflect the effect of unrealized losses on commodity derivatives.

The following table presents that breakdown of our revenues for the periods specified below excluding theunrealized effects of our commodity derivative contracts.

	For the Year Ended December 31,		For the Three Months Ended March 31,	
	2021	2020	2022	2021
Crude oil sales	32%	55%	50%	23%
Natural gas sales	56%	37%	38%	67%
Natural gas liquid sales	12%	8%	12%	10%

Revenue excluding the unrealized effects of commodity derivative contracts is anon-GAAP supplemental financial measure that management and external users of our combined financial statements, such as investors, lenders and others (including industry analysts and rating agencies who will be using such measure), may use for the periods presented to more effectively evaluate our operating performance and our results of operation from period to period without giving effect to non-cash gains and losses. The GAAP measures most directly comparable to revenue excluding the unrealized effects of commodity derivative contracts is GAAP revenue. You should not consider revenue excluding the unrealized effects of commodity derivative contracts in isolation or as a substitute for analysis of our results as reported under GAAP.

Production volumes

Our ability to generate sufficient cash from operations to pay cash distributions to unitholders is a function of two primary variables: (i) production volumes and (ii) commodity prices. Production volumes directly impact our revenue. Any negative effect on production volumes could have a material adverse effect on our business, financial condition, results of operations and cash available for distribution. The following table presents historical production volumes for our properties for the periods specified below:

	For the Year Ended December 31,		For the Three Months Ended March 31,	
	2021	2020	2022	2021
Oil and condensate (MBbls)	1,033	940	517	191
Natural gas liquids (MBbls)	1,089	860	302	244
Natural gas (MMcf)	30,590	22,132	7,550	7,506
Total (MBoe)	7,220	5,489	2,077	1,686
Average net sales (MBoe/d)	20	15	23	19

Sales volumes directly impact our results of operations. For more information about sales volumes, see "—Historical Results of Operations."

As reservoir pressures decline, production from a given well or formation decreases. Maintaining or growing our future production and reserves will depend on our ability to continue to replace current production with new reserves. Accordingly, we plan to focus on maintaining reserves through both the drill bit and acquisitions, while maintaining a conservative financial profile. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel, and successfully identify and consummate acquisitions. See "Risk Factors—Risks Related to Our Business and the Oil, Natural Gas and NGL Industry" for a discussion of these and other risks affecting our proved reserves and production.

Realized commodity prices

Our results of operations depend on many factors, particularly the price of our commodity production and our ability to market our production effectively. Oil and natural gas prices have historically been volatile and currently are at near record-high levels. During the period from January 1, 2021 through June 30, 2022, prices for crude oil and natural gas reached a high of $123.70 per Bbl and $23.86 per MMBtu, respectively, and a low of $47.62 per Bbl and $2.43 per MMBtu, respectively. A future decline in commodity prices may adversely affect our business, financial condition or results of operations. Lower commodity prices may not only decrease our revenues, but also the amount of oil and natural gas that we can produce economically. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our Credit Facility, which is redetermined semi-annually. See "—Liquidity and Capital Resources—Revolving credit agreement."

The NYMEX WTI, for oil prices, and NYMEX Henry Hub, for gas prices, are widely used benchmarks for the pricing of oil and natural gas in the United States. The price we receive for our oil and natural gas production is generally different than the NYMEX price because of adjustments for delivery location (“*basis*”), relative quality and other factors. As such, our revenues are sensitive to the price of the underlying commodity to which they relate. The following is a comparison of average pricing excluding and including the effects of derivatives:

	For the Year Ended December 31,		For the Three Months Ended March 31,	
	2021	2020	2022	2021
Average prices:				
Oil (Bbl)				
Average NYMEX Price	$68.11	$ 39.32	$ 95.01	$ 58.14
Average Realized Price (excluding derivatives)	$67.41	$ 37.11	$ 93.62	$ 56.84
Average Realized Price (including derivatives)	$67.74	$ 62.84	$ (4.89)	$ 56.84
Differential to NYMEX	$ (0.70)	$ (2.21)	$ (1.39)	$ (1.30)
Natural Gas (Mcf)				
Average NYMEX Price	$ 3.89	$ 2.03	$ 4.67	$ 3.50
Average Realized Price (excluding derivatives)	$ 4.00	$ 1.89	$ 4.90	$ 4.26
Average Realized Price (including derivatives)	$ 4.27	$ 1.85	$ (1.34)	$ 4.26
Differential to NYMEX	$ 0.11	$ (0.14)	$ 0.23	$ 0.76
Natural gas liquids (Bbl)				
Average Realized Price (excluding derivatives)	$25.16	$ 10.07	$ 38.30	$ 19.62
Average Realized Price (including derivatives)	$25.60	$ 10.07	$ 10.35	$ 19.62
High and low NYMEX prices:				
Oil (Bbl)				
High	$84.65	$ 63.27	$ 123.70	$ 66.09
Low	$47.62	$ (37.63)	$ 76.08	$ 47.62
Natural gas (Mcf)				
High	$23.86	$ 3.14	$ 6.70	$ 23.86
Low	$ 2.43	$ 1.41	$ 3.73	$ 2.45

Hedging activities

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for our production. In most of our current positions, our hedging activity may also reduce our ability to benefit from increases in commodity prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices, and conversely, we will recognize gains to the extent our derivatives contract prices are higher than market prices. Our policy is to hedge opportunistically a portion of our production at commodity prices management deems attractive. We are also subject to certain hedging requirements pursuant to our Credit Facility. See “—Liquidity and Capital Resources—Revolving credit agreement.” While there is a risk we may not be able to realize the full benefits of rising prices, management may continue its hedging strategy because of the benefits of predictable, stable cash flows. See “—Quantitative and Qualitative Disclosure About Market Risk —Commodity Price Risk” for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

The price we receive for our oil and natural gas production is generally less than the NYMEX prices because of adjustments for basis, relative quality and other factors. We have entered into basis swap agreements that effectively fix the basis adjustment for our delivery locations.

In the year ended December 31, 2021, all of our hedging activities increased oil revenue $0.3 million, NGL revenue $0.5 million and gas revenue $8.2 million. In the year ended December 31, 2020, all of our hedging activities increased oil revenue $24.2 million and decreased gas revenue $0.9 million. In the three months ended March 31, 2022, all of our hedging activities decreased oil revenue $50.9 million, NGL revenue $8.4 million and gas revenue $47.2 million. In the three months ended March 31, 2021, all of our hedging activities had no effect on revenue.

The following tables summarize our open oil, NGL and natural gas hedging production as of March 31, 2022. Prices to be realized for hedged production will be less than these NYMEX prices because of location, quality and other adjustments.

Crude Oil—Swaps **Production Period**	**Bbls per Day**	**Weighted Average NYMEX Price per Bbl**
April 2022—December 2022	3,500	$ 71.28
January 2023—December 2023	2,500	$ 68.87
January 2024—June 2024	2,000	$ 63.27

Crude Oil Basis Swaps—West Texas Midland **Production Period**	**Bbls per Day**	**Weighted Average NYMEX Price per Bbl(a)**
April 2022—December 2022	3,000	$ 0.55

(a) Increases to NYMEX oil price for delivery location.

Crude Oil—Roll Component **Production Period**	**Bbls per Day**	**Weighted Average NYMEX Price per Bbl(a)**
April 2022—December 2022	5,000	$ 0.50
January 2023—December 2023	1,000	$ 0.68

(a) Increases to NYMEX oil price for roll component.

Natural Gas Liquids—Swaps **Production Period**	**Gallons per Day**	**Weighted Average NGL OPIS Price per Gallon**
Ethane		
April 2022—December 2022	63,000	$ 0.33
January 2023—December 2023	63,000	$ 0.27
January 2024—June 2024	63,000	$ 0.23
Propane		
April 2022—December 2022	31,500	$ 1.01

Natural Gas—Swaps **Production Period**	**MMBtu per Day**	**Weighted Average NYMEX Price per MMBtu**
April 2022—December 2022	45,000	$ 4.23
January 2023—December 2023	35,000	$ 3.51
January 2024—June 2024	30,000	$ 3.26

Natural Gas—Collars Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu Floor	 Ceiling
April 2022—December 2022	15,000	$ 3.50	$ 5.85
January 2023—March 2023	5,000	$ 5.00	$ 9.85
January 2024—June 2024	5,000	$ 3.75	$ 7.25

Natural Gas Basis Swaps—San Juan Production Period	MMBtu per Day	Weighted Average Sell Basis Price per MMBTU(a)
April 2022—December 2022	70,000	$ 0.22
January 2023—December 2023	20,000	$ 0.15

(a) Reductions to NYMEX gas price for delivery location.

Principal Components of Our Cost Structure

Production expenses

Production expenses are the costs incurred in the operation of producing properties and include workover costs. Expenses for labor, overhead and repairs and maintenance comprise the most significant components of production expenses. Lease operating expenses do not include general and administrative expenses or severance or ad valorem taxes. We evaluate production expenses on a per Boe basis to monitor changes in production expenses to determine that costs are at an acceptable level. We monitor our operations to ensure that we are incurring lease operating expenses at an acceptable level. Although we strive to reduce our lease operating expenses, these expenses can increase or decrease on a per unit basis as a result of various factors as we operate and develop our properties or make acquisitions of properties.

Taxes, transportation, and other expenses

Taxes, transportation, and other expenses consist primarily of gathering fees and processing fees, transportation costs, severance taxes, and ad valorem taxes. Gathering, processing and transportation costs are recognized when control of the natural gas we sell occurs at the tailgate of the processing plant. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from production sold at fixed rates established by state or local taxing authorities. In general, the severance taxes we pay correlate to the changes in oil and natural gas revenues. We are also subject to ad valorem taxes in the counties where our production is located. We evaluate taxes, transportation, and other expense on a per Boe basis to monitor costs to ensure that they are at acceptable levels. Taxes, transportation, and other expenses can also be influenced by acquisitions, commodity prices, changes in values of our properties, sales mix and acquisitions.

Depletion, depreciation, and amortization

Depreciation, depletion, and amortization ("*DD&A*") is the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas. We follow the successful efforts method of accounting, capitalizing costs of successful acquisitions and exploratory wells, which are then allocated to each unit of production using the unit of production method, and expensing costs of unsuccessful exploratory wells. Exploratory geological and geophysical costs are expensed as incurred. All developmental costs are capitalized. We generally pursue acquisition and development of proved reserves as opposed to exploration activities. Changes in DD&A are a result of production and changes in the estimated reserves during the period.

General and administrative expenses

General and administrative expenses consist primarily of personnel related costs and are partially offset by certain reimbursements of overhead expenses, including Texas gross margin taxes. In connection with the consummation of this offering, we expect to incur additional costs related to being a public company. However, we do not expect to experience a material change in our cash cost structure, other than as set forth below under "Factors Affecting the Comparability of Our Financial Condition and Results of Operations."

Interest expense

Interest expense is primarily a result of interest on our borrowings on our Credit Facility to fund operations and acquisitions of properties as well as the amortization of debt issuance costs associated with these borrowings. Interest expense can fluctuate with our level of indebtedness as well as changes in interest rates.

Income Tax

Texas does not currently impose a personal income tax on individuals, but it does impose an entity level tax (to which we will be subject) on corporations and other entities. While we do not pay income tax in Texas, we are subject to Texas franchise taxes.

How We Evaluate Our Operations

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

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

Adjusted EBITDAX

We define Adjusted EBITDAX as net income (loss) before (1) interest income, (2) interest expense, (3) depreciation, depletion and amortization, (4) impairment expenses, (5) accretion of discount on asset retirement obligations, (6) exploration expenses, (7) unrealized (gain) losses on commodity derivative contracts, (8) non-cash incentive compensation, (9) non-cash (gain) loss on forgiveness of debt and (10) certain othernon-cash expenses.

Adjusted EBITDAX is not a measure of net income as determined by U.S. GAAP. Management believes Adjusted EBITDAX is useful because it allows them to more effectively evaluate the financial performance of our assets from period to period and against our peers without regard to financing methods or capital structure.

Cash Available for Distribution

Although we have not quantified cash available for distribution on a historical basis, after the closing of this offering, we intend to use cash available for distribution to assess our ability to internally fund our exploration and development activities, pay distributions, and to service or incur additional debt. We define cash available for distribution as Adjusted EBITDAX less cash interest expense, exploration expense and development costs. Development costs includes all of our capital expenditures made for oil and gas properties, other than acquisitions. Cash available for distribution will not reflect changes in working capital balances.

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

Factors Affecting the Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, primarily for the following reasons:

Property acquisitions

We have completed three prior significant acquisitions in the past two years that affect the comparability of results of operations between 2020 and 2021 to some extent. We intend to continue to grow our operations through prudent acquisitions. Additionally, it is possible that we will effect divestitures of certain of our assets. We may enter into acquisitions and/or divestitures in the ordinary course of business that may affect our future operations, including our revenues and operating expenses. The following is a summary of our significant acquisition activity that occurred from the beginning of 2020 to the date of this prospectus:

- *San Juan Acquisition*. The acquisition in June 2020 of producing properties in the San Juan Basin of New Mexico and Colorado for approximately $10.2 million.

- *Chevron Vacuum Acquisition*. The acquisition in November 2021 of producing properties and a gas processing plant in the Permian Basin of New Mexico and CO_2 assets in Colorado for approximately $175.4 million.

- *Chevron Andrews Parker Acquisition*. The acquisition in December 2021 of producing properties in the Permian Basin of Texas for approximately $43.8 million.

Supply, demand, market risk and their impact on oil prices.

The oil industry is cyclical and commodity prices are highly volatile. During the period from January 1, 2021 through June 30, 2022, prices for crude oil reached a high of $123.70 per Bbl and a low of $47.62 per Bbl. Crude oil prices were impacted by a variety of factors affecting current and expected supply and demand dynamics, including: strong demand for crude oil, domestic supply reductions, OPEC control measures and market disruptions resulting from the Russia-Ukraine war and sanctions on Russia. Since the Russia-Ukraine conflict first commenced, WTI crude oil prices have trended higher, rising from $92.81 per Bbl on February 24, 2022 to a high of $123.70 per Bbl in March 2022 and $104.79 as of July 8, 2022. These prices experience large swings, sometimes on a day-to-day or week-to-week basis.

Other factors impacting supply and demand include weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, strength of the U.S. dollar as well as other factors, the majority of which are outside of our control. In addition to these uncontrollable influences, there is an ongoing shift of relaxing COVID-19 containment measures worldwide, which may increase economic activity and energy demand. As a result of these external factors, we expect global commodity price volatility will continue throughout 2022. Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production. Please see "Risk Factors—Risks Related to the Natural Gas, NGL and Oil Industry and Our Business—Commodity prices are volatile—A sustained decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

Public company expenses

Upon the completion of this offering, we expect to incur incrementalnon-recurring costs related to our transition to a publicly traded partnership, including the costs of this initial public offering and the costs associated with the initial implementation of our internal control implementation and testing. We also expect to incur additional significant and recurring expenses as a publicly traded partnership, including costs associated with the employment of additional personnel, compliance under the Exchange Act, annual and quarterly reports to shareholders, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation. The direct, incremental general and administrative expenses are not included in our historical or pro forma financial statements.

Derivatives

To reduce the impact of fluctuations in oil, NGL and natural gas prices on our revenues, we periodically enter into commodity derivative contracts with respect to certain of our oil, NGL and natural gas production through various transactions that limit the risks of fluctuations of future prices. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations.

Impairment

We evaluate our producing properties for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. When assessing proved properties for impairment, we compare the expected undiscounted future cash flows of the proved properties to the carrying amount of the proved properties to determine recoverability. If the carrying amount of proved properties exceeds the expected undiscounted future cash flows, the carrying amount is written down to the properties' estimated fair value, which is measured as the present value of the expected future cash flows of such properties. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, and a risk-adjusted discount rate. The proved property impairment test is primarily impacted by future commodity prices, changes in estimated reserve quantities, estimates of future production, overall proved property balances, and depletion expense. If pricing conditions decline or are depressed, or if there is a negative impact on one or more of the other components of the calculation, we may incur proved property impairments in future periods.

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Results of Operations

Three Months Ended March 31, 2022 Compared to the Three Months Ended March 31, 2021

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
	(in thousands)	
Revenues:		
Oil and condensate sales(1)	$ (2,530)	$ 10,875
Natural gas liquids sales(2)	$ 3,121	$ 4,777
Natural Gas sales(3)	$ (10,129)	$ 31,975
Total revenues	$ (9,538)	$ 47,627
Expenses:		
Production expenses	$ 25,026	$ 14,316
Exploration expenses	$ 87	$ 44
Taxes, transportation, and other	$ 23,487	$ 12,704
Depreciation, depletion, and amortization	$ 9,780	$ 9,245
Accretion of discount in asset retirement obligations	$ 1,477	$ 1,320
General and administrative	$ 396	$ (89)
Total expenses	$ 60,253	$ 37,540
Operating income (loss):	$ (69,791)	$ 10,087
Other income (expense):		
Other income	$ 5,872	$ 15
Interest income	$ 6	$ 3
Interest expense	$ (1,670)	$ (1,365)
Total other income (expense)	$ 4,208	$ (1,347)
Net income (loss):	$ (65,583)	$ 8,740

(1) Oil and condensate prices include both realized and unrealized losses from derivatives. The unrealized losses were $43.2 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021. The realized losses were $7.7 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021.

(2) Natural gas liquids prices include both realized and unrealized losses from derivatives. The unrealized losses were $7.2 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021. The realized losses were $1.2 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021.

(3) Natural gas prices include both realized and unrealized losses from derivatives. The unrealized losses were $41.0 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021. The realized losses were $6.2 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021.

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

	Three Months Ended March 31,	
	2022	2021
Sales:		
Oil and condensate sales (MBbls)	517	191
Natural gas liquids sales (MBbls)	302	244
Natural gas sales (MMcf)	7,550	7,506
Total (MBoe)	2,077	1,686
Total (MBoe/d)	23	19
Average sales prices:		
Oil and condensate (per Bbl)(1)	$ (4.89)	$ 56.84
Oil and condensate (excluding the effects of derivatives) (per Bbl)	$ 93.62	$ 56.84
Natural gas liquids (per Bbl)(2)	$ 10.35	$ 19.62
Natural gas liquids (excluding the effects of derivatives) (per Bbl)	$ 38.30	$ 19.62
Natural gas (per Mcf)(3)	$ (1.34)	$ 4.26
Natural gas (excluding the effects of derivatives) (per Mcf)	$ 4.90	$ 4.26
Expense per Boe:		
Production	$ 12.05	$ 8.49
Taxes, transportation and other	$ 11.31	$ 7.54
Depreciation, depletion and amortization	$ 4.71	$ 5.48
General and administrative expenses	$ 0.19	$ (0.05)

(1) Oil and condensate prices include both realized and unrealized losses from derivatives. The unrealized losses were $43.2 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021. The realized losses were $7.7 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021.

(2) Natural gas liquids prices include both realized and unrealized losses from derivatives. The unrealized losses were $7.2 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021. The realized losses were $1.2 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021.

(3) Natural gas prices include both realized and unrealized losses from derivatives. The unrealized losses were $41.0 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021. The realized losses were $6.2 million for the three months ended March 31, 2022 and $0.0 million for the three months ended March 31, 2021.

Revenues

Revenues decreased $57.2 million, or 120%, from $47.6 million for the three months ended March 31, 2021 to ($9.5) million for the three months ended March 31, 2022. The decrease was primarily attributable to losses on our hedging activity of $106.5 million, of which $91.3 million were unrealized losses and $15.2 million were realized losses, partially offset by an increase in production of 391 MBoe primarily as a result of additional production from the acquired Vacuum properties of 297 MBoe and Andrews Parker properties of 75 MBoe, respectively, resulting in an increase in revenue of $32.9 million. The decrease was also offset by an increase in the average selling price, excluding the effects of derivatives, on oil of 65% resulting in an increase in revenue of $7.0 million, on NGLs of 95% resulting in an increase in revenue of $4.6 million, and on natural gas of 15% resulting in an increase in revenue of $4.8 million.

Production expenses

Production expenses increased $10.7 million, or 75%, from $14.3 million for the three months ended March 31, 2021 to $25.0 million for the three months ended March 31, 2022. The increase is primarily attributable to the increased production associated with the addition of the Vacuum and Andrews Parker properties of $8.6 million as well as increased maintenance and well work costs.

On a per unit basis, production expenses increased from $8.49 per Boe sold for the three months ended March 31, 2021 to $12.05 per Boe sold for the three months ended March 31, 2022. The increase is primarily related to the increased costs per Boe from the acquired Vacuum and Andrews Parker properties due to the acquired properties having a higher percentage of oil production, which is more expensive on a Boe basis than natural gas production.

Taxes, transportation, and other

Taxes, transportation, and other increased $10.8 million, or 85%, from $12.7 million for the three months ended March 31, 2021 to $23.5 million for the three months ended March 31, 2022. The increase is primarily attributable to the increased production associated with the addition of the Vacuum and Andrews Parker properties of $6.8 million as well as an increase in oil, NGLs, and natural gas prices.

On a per unit basis, taxes, transportation, and other increased from $7.54 per Boe sold for the three months ended March 31, 2021 to $11.31 per Boe sold for the three months ended March 31, 2022. The increase is primarily related to the higher commodity prices and change in production mix.

Depreciation, depletion, and amortization

Depreciation, depletion, and amortization increased $0.5 million, or 6%, from $9.3 million for the three months ended March 31, 2021 to $9.8 million for the three months ended March 31, 2022. The increase is primarily attributable to the increased production associated with the addition of the Vacuum and Andrews Parker properties in the fourth quarter of 2021 of $3.0 million partially offset by a reduction of $2.5 million from our other assets as a result of a lower average DD&A rate partially offset by higher production.

On a per unit basis, depreciation, depletion, and amortization decreased from $5.48 per Boe sold for the three months ended March 31, 2021 to $4.71 per Boe sold for the three months ended March 31, 2022. The decrease is primarily related to changes in reserves.

General and administrative

General and administrative ("*G&A*") expenses increased $0.5 million, or 545%, from ($0.1) million for the three months ended March 31, 2021 to $0.4 million for the three months ended March 31, 2022. The increase is primarily attributable to the increased costs related to the acquired Vacuum and Andrews Parker properties of $2.9 million partially offset by a reduction of $2.3 million from employee headcount reductions.

On a per unit basis, G&A expense increased from ($0.05) per Boe sold for the three months ended March 31, 2021 to $0.19 per Boe sold for the three months ended March 31, 2022. The increase is primarily related to decreased cost recovery and partially offset by decreased costs and increased production.

Other income

Other income increased $5.9 million from $0.0 million for the three months ended March 31, 2021. The increase is primarily attributable to the recognition of $5.7 million of CO_2 and plant income related to the acquired Vacuum properties. The CO_2 and plant income is wholly-dependent and ancillary to the operations of the Vacuum properties.

Interest expense

Interest expense increased $0.3 million, or 22%, from $1.4 million for the three months ended March 31, 2021 to $1.7 million for the three months ended March 31, 2022. The increase is primarily attributable to the additional borrowings to fund the Chevron Acquisitions and a higher interest rate.

Year Ended December 31, 2021 Compared to the Year Ended December 31, 2020

	December 31, 2021	December 31, 2020
	(in thousands)	
Revenues:		
Oil and condensate sales	$ 69,971	$ 59,070
Natural gas liquids sales	$ 27,875	$ 8,660
Natural Gas sales	$ 130,498	$ 41,034
Total revenues	$ 228,344	$ 108,764
Expenses:		
Production expenses	$ 69,256	$ 49,146
Exploration expenses	$ 124	$ 55
Taxes, transportation, and other	$ 58,040	$ 27,509
Depreciation, depletion, and amortization	$ 39,889	$ 42,322
Impairment	$ —	$ 134,097
Accretion of discount in asset retirement obligations	$ 4,670	$ 3,940
General and administrative	$ 12,175	$ 6,995
Total expenses	$ 184,154	$ 264,064
Operating income (loss):	$ 44,190	$ (155,300)
Other income (expense):		
Other income	$ 14,139	$ 72
Interest income	$ 16	$ 194
Interest expense	$ (5,870)	$ (8,204)
Total other income (expense)	$ 8,285	$ (7,938)
Net income (loss):	$ 52,475	$ (163,238)

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The following table provides a summary of our sales volumes, average prices and operating expenses on a per Boe basis for the periods indicated:

	Year Ended December 31,	
	2021	2020
Sales:		
Oil and condensate sales (MBbls)	1,033	940
Natural gas liquids sales (MBbls)	1,089	860
Natural gas sales (MMcf)	30,590	22,132
Total (MBoe)	7,220	5,489
Total (MBoe/d)	20	15
Average sales prices:		
Oil and condensate (per Bbl)(1)	$ 67.74	$ 62.84
Oil and condensate (excluding the effects of derivatives) (per Bbl)	$ 67.41	$ 37.11
Natural gas liquids (per Bbl)(2)	$ 25.60	$ 10.07
Natural gas liquids (excluding the effects of derivatives) (per Bbl)	$ 25.16	$ 10.07
Natural gas (per Mcf)(3)	$ 4.27	$ 1.85
Natural gas (excluding the effects of derivatives) (per Mcf)	$ 4.00	$ 1.89
Expense per Boe:		
Production expenses	$ 9.59	$ 8.95
Taxes, transportation and other	$ 8.04	$ 5.01
Depreciation, depletion and amortization	$ 5.52	$ 7.71
General and administrative expenses	$ 1.69	$ 1.27

(1) Oil and condensate prices include both realized and unrealized gains and losses from derivatives. The unrealized portion were gains of $0.3 million for the year ended December 31, 2021 and were losses of $2.9 million for the year ended December 31, 2020. The realized gains were $0.0 million for the year ended December 31, 2021 and $27.1 million for the year ended December 31, 2020.

(2) Natural gas liquids prices include unrealized gains from derivatives. The unrealized gains were $0.5 million for the year ended December 31, 2021 and $0.0 million for the year ended December 31, 2020.

(3) Natural gas prices include both realized and unrealized gains and losses from derivatives. The unrealized gains were $8.2 million for the year ended December 31, 2021 and $0.1 million for the year ended December 31, 2020. The realized losses were $0.0 million for the year ended December 31, 2021 and $1.0 million for the year ended December 31, 2020.

Revenues

Revenues increased $119.6 million, or 110%, from $108.8 million for the year ended December 31, 2020 to $228.3 million for the year ended December 31, 2021. The increase was primarily attributable to an increase in the average selling price, excluding the effects of derivatives, on oil of 82%, resulting in an increase in revenue of $28.5 million, on NGLs of 150%, resulting in an increase in revenue of $13.0 million, and on natural gas of 111%, resulting in an increase in revenue of $46.6 million. The increase was also attributable to an increase in production of 1,731 MBoe primarily as a result of additional production from the acquired San Juan properties of 1,723 MBoe and Vacuum properties of 177 MBoe partially offset by decreased production in our other properties, resulting in an increase in revenue of $45.8 million partially offset by decreased gains on our hedging activity of $14.3 million. The $14.3 million decrease from our hedging activity includes a decrease in the realized portion of $26.2 million partially offset by an increase in the unrealized portion of $11.9 million.

Production expenses

Production expenses increased $20.1 million, or 41%, from $49.1 million for the year ended December 31, 2020 to $69.3 million for the year ended December 31, 2021. The increase is primarily attributable to the increased production associated with the addition of the San Juan properties of $12.7 million and the Vacuum properties of $5.5 million as well as increased maintenance and well work costs.

On a per unit basis, production expenses increased from $8.95 per Boe sold for the year ended December 31, 2020 to $9.59 per Boe sold for the year ended December 31, 2021. The increase is primarily related to the increased costs per Boe from the acquired Vacuum properties as well as the increased maintenance and well work costs.

Taxes, transportation, and other

Taxes, transportation, and other increased $30.5 million, or 111%, from $27.5 million for the year ended December 31, 2020 to $58.0 million for the year ended December 31, 2021. The increase is primarily attributable to the increased production associated with the addition of the San Juan properties of $23.6 million and the Vacuum properties of $2.7 million as well as an increase in oil, NGLs, and natural gas prices.

On a per unit basis, taxes, transportation, and other increased from $5.01 per Boe sold for the year ended December 31, 2020 to $8.04 per Boe sold for the year ended December 31, 2021. The increase is primarily related to the higher commodity prices and change in production mix.

Depreciation, depletion, and amortization

Depreciation, depletion, and amortization decreased $2.4 million, or 6%, from $42.3 million for the year ended December 31, 2020 to $39.9 million for the year ended December 31, 2021. The decrease is primarily attributable to a reduction of $7.0 million from our other assets as a result of lower production and lower rate, partially offset by increased production associated with the addition of the San Juan properties of $3.3 million and Vacuum properties of $1.3 million.

On a per unit basis, depreciation, depletion, and amortization decreased from $7.71 per Boe sold for the year ended December 31, 2020 to $5.52 per Boe sold for the year ended December 31, 2021. The decrease is primarily related to changes in production mix and the effect of the 2020 impairment discussed below.

Impairment of oil and gas properties

For the year ended December 31, 2020, we recognized an impairment of long-lived assets of $134.1 million for our assets primarily due to a lower net commodity price environment for some of our oil and natural gas assets.

General and administrative

General and administrative ("*G&A*") expenses increased $5.2 million, or 74%, from $7.0 million for the year ended December 31, 2020 to $12.2 million for the year ended December 31, 2021. The increase is primarily attributable to the increased costs related to the acquired Vacuum properties of $2.7 million as well as decreased cost reimbursements.

On a per unit basis, G&A expense increased from $1.27 per Boe sold for the year ended December 31, 2020 to $1.69 per Boe sold for the year ended December 31, 2021. The increase is primarily related to decreased COPAS related cost reimbursements partially offset by increased production.

Other income

Other income increased $14.1 million from $0.1 million for the year ended December 31, 2020. The increase is primarily attributable to forgiveness of debt of $9.2 million under the U.S. Government's Paycheck Protection Program from the Small Business Administration, the $3.6 million non-cash gain on sale of properties due to the write off of related asset retirement obligations and the recognition of $2.0 million of CO_2 and plant income related to the acquired Vacuum properties partially offset by the $0.6 million write off of certain assets.

Interest expense

Interest expense decreased $2.3 million, or 28%, from $8.2 million for the year ended December 31, 2020 to $5.9 million for the year ended December 31, 2021. The decrease is primarily attributable to decreased borrowings and a lower interest rate.

Liquidity and Capital Resources

Following the consummation of this offering, our primary sources of liquidity and capital will be cash flows generated by operating activities and borrowings under our Credit Facility. Outstanding borrowings under our Credit Facility were $145.0 million at December 31, 2021 and $130.0 million at March 31, 2022, and the remaining availability under our Credit Facility was $20.0 million at December 31, 2021 and $35.0 million at March 31, 2022. Additionally, we had positive net working capital (including cash and excluding the effects of derivative instruments) of $17.6 million at December 31, 2021 and $34.4 million at March 31, 2022. After giving effect to this offering and the use of proceeds as described under "Use of Proceeds" as of March 31, 2022, we would have had $ outstanding, $ million available under our Credit Facility (based on the outstanding balance on the Credit Facility subsequent to the offering and the borrowing base as of March 31, 2022) and $15.4 million of cash (based on our cash balance as of March 31, 2022), for total liquidity of $ million.

As a publicly traded partnership, our primary sources of liquidity and capital resources will be from cash flow generated by operating activities and borrowings under our Credit Facility. Historically, our primary sources of liquidity have also included capital contributions by our equity holders, but we do not expect to rely on management or our partners for capital following the completion of this offering. We expect we will need to utilize the public equity or debt markets and bank financings to fund future acquisitions or capital expenditures, but the price at which our common units will trade could be diminished as a result of the limited voting rights of unitholders. We expect to be able to issue additional equity and debt securities from time to time as market conditions allow to facilitate future acquisitions. We expect to repay any debt incurred by us to complete such acquisitions in order to meet our long-term goal of remaining substantially debt free. Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations or to refinance our indebtedness will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices, particularly for oil and natural gas, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory, weather and other factors.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to our unitholders. In making cash distributions, our general partner will attempt to avoid large variations in the amount we distribute from quarter to quarter. In order to facilitate this, our partnership agreement permits our general partner to establish cash reserves to be used to pay distributions for any one or more of the next four quarters.

In addition, our partnership agreement permits us to borrow funds to make distributions to our unitholders. We may borrow to make distributions to our unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long-term, but short-term factors have caused available cash from operations to be insufficient to sustain our level of distributions. For example, we generally intend to hedge a significant portion of our production. We generally will be required to settle our commodity hedge derivatives within twenty-five days of the end of the month. As is typical in the oil and gas industry, we do not generally receive the proceeds from the sale of our hedged production until 20 to 60 days following the end of the month. As a result, when commodity prices increase above the fixed price in the derivative contracts, we will be required to pay the derivative counterparty the difference between the fixed price in the derivative contract and the market price before we receive the proceeds from the sale of the hedged production. If this occurs, we may borrow to fund our distributions.

Our acquisition and development expenditures consist of acquisitions of proved, unproved and other property and development expenditures. Our capital expenditures including acquisitions were $5.8 million for the three months ended March 31, 2022 and $1.5 million for the three months ended March 31, 2021. Our capital expenditures including acquisitions were $227.8 million for the year ended December 31, 2021 and $16.7 million for the year ended December 31, 2020.

We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations and to satisfy the requirement under our Credit Facility to hedge at least (a) 75% of reasonably anticipated projected production of proved developed producing reserves for the 12-month period following January 1, 2022 and (b) thereafter 50% of reasonably anticipated projected production of proved developed producing reserves for the 30-month period following the date of any hedging transaction. However, as of any time, if the net leverage ratio (the ratio of total net debt-to-EBITDAX) is less than or equal to 1.0 to 1.0 and the cash and cash equivalents on hand are equal to or greater than 20% of the borrowing base then in effect, the minimum required hedge volume for month one through month 24 will be reduced to 50%. Our Credit Facility prohibits us from hedging more than 90% of our reasonably projected production for any fiscal year. See Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement" for more information. Our policy is to consider hedging a portion of our production at commodity prices management deems attractive.

Our budgets for drilling, completion and recompletion activities and facilities costs are approximately $30 million for 2022 and approximately $30 million for 2023. We expect to allocate most of our 2022 budget and the majority of our 2023 budget to projects focused on enhancing existing production. For the three months ended March 31, 2022, we have made approximately $0.7 million of drilling, completion and recompletion expenditures. We expect to fund these capital expenditures from cash flow from operations.

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

Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our distributions, meet our debt obligations and fund our 2022 and 2023 capital development programs from cash flow from operations and the net proceeds of this offering.

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

Cash flows

The following table summarizes our cash flows for the periods indicated:

	For the Year Ended December 31,		For the Three Months Ended March 31,	
	2021	2020	2022	2021
	(in thousands)			
Net cash provided by operating activities	$ 73,726	$ 18,964	$ 28,665	$ 21,859
Net cash used by investing activities	$ (227,801)	$ (16,718)	$ (5,792)	$ (1,492)
Net cash provided by (used in) financing activities	$ 139,689	$ 14,067	$ (15,064)	$ (20,004)

Three Months Ended March 31, 2022 Compared to Three Months Ended March 31, 2021

Net cash provided by operating activities

Net cash provided by operating activities increased $6.8 million for the three months ended March 31, 2022 compared to the three months ended March 31, 2021 due to a change in non-cash derivative loss of $106.5 million and changes in non-cash expenses of $0.7 million partially offset by decreased net income of $74.3 million, increased realized derivative losses of $15.2 million and changes in operating assets and liabilities of $10.9 million. Excluding the $91.3 million of non-cash effects of derivative losses, net income would have increased $17.0 million primarily as a result of improved prices in 2022 compared to 2021 and the resulting improvement in operating activities.

Net cash used by investing activities

Net cash used by investing activities increased $4.3 million for the three months ended March 31, 2022 compared to the three months ended March 31, 2021 due to an increase in proved property acquisitions of $3.7 million and other property of $1.3 million partially offset by a decrease in development costs of $0.7 million.

Net cash provided by (used in) financing activities

	For the Three Months Ended March 31,	
	2022	2021
	(in thousands)	
Proceeds from long-term debt	$ 415,000	$ 386,000
Payments on long-term debt	$ (430,000)	$ (406,000)
Debt issuance costs	$ (64)	$ (4)
Net cash used in financing activities	$ (15,064)	$ (20,004)

Net cash used in financing activities decreased $4.9 million for the three months ended March 31, 2022 compared to the three months ended March 31, 2021 due to a decrease in net repayments under our Credit Facility of $5.0 million partially offset by an increase in debt issuance costs of $0.1 million.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Net cash provided by operating activities

Net cash provided by operating activities increased $54.8 million for the year ended December 31, 2021 compared to the year ended December 31, 2020 due to an increase in net income of $215.7 million partially offset by a decrease in non-cash expenses of $135.8 million, a change in non-cash derivative gain of $11.9 million, forgiveness of debt of $9.2 million, a decrease in non-cash incentive compensation of $1.8 million, changes in other non-cash items of $1.4 million and changes in operating assets and liabilities of $0.8 million. The improvement in net cash provided by operating activities is primarily related to improved prices in 2021 compared to 2020 and increased production as a result of owning the San Juan Basin properties for the entire year and the acquisition of the Vacuum properties in 2021 partially offset by increased costs.

Net cash used in investing activities

Net cash used in investing activities increased $211.1 million for the year ended December 31, 2021 compared to the year ended December 31, 2020 due to an increase in proved property acquisitions of $175.0 million, other property additions of $33.0 million and development costs of $3.4 million partially offset by a decrease in unproved property acquisitions of $0.3 million.

Net cash provided by (used in) financing activities

	For the Year Ended December 31,	
	2021	2020
	(in thousands)	
Proceeds from long-term debt	$ 1,437,000	$ 1,932,152
Payments on long-term debt	$ (1,427,000)	$ (1,968,000)
Proceeds from temporary equity investment	$ —	$ 50,695
Proceeds from partners' investment	$ 132,660	$ —
Debt issuance costs	$ (2,832)	$ (709)
Payment on vesting of restricted units	$ —	$ (40)
Distributions	$ (139)	$ (31)
Net cash provided by financing activities	$ 139,689	$ 14,067

Net cash provided by financing activities increased $125.6 million for the year ended December 31, 2021 compared to the year ended December 31, 2020 due to an increase in proceeds received from partners of $82.0 million and in net borrowings under our Credit Facility of $45.8 million partially offset by an increase in debt issuance costs of $2.1 million and distributions of $0.1 million.

Revolving credit agreement

On November 1, 2021, we entered into a new four-year, $165 million senior secured credit facility (the "Credit Facility") with certain commercial banks. Our Credit Facility permits us to use proceeds for general partnership purposes including distributions to our unitholders. Our obligations under the Credit Facility are secured by all of our assets, including (i) our interest in Cross Timbers, (ii) all our deposit accounts, securities accounts, and commodities accounts, (iii) any receivables owed to us by the joint venture and (iv) any oil and gas properties owned directly by us and our wholly-owned subsidiaries. The facility has a maturity date of November 1, 2025. We use the facility for general partnership purposes. In connection with entering into the Credit Facility, as of March 31, 2022, we incurred financing fees and expenses of approximately $2.8 million before accumulated amortization of $0.3 million. 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. As of March 31, 2022, we had $130 million in borrowings outstanding under our Credit Facility and $35 million in availability. After giving effect to this offering and the use of proceeds as described under "Use of Proceeds" as of March 31, 2022, we would have had $ outstanding and $ million available under our Credit Facility, based on the outstanding balance on the Credit Facility subsequent to the offering and the borrowing base as of March 31, 2022.

Under our Credit Facility, the borrowing base is determined based on the value of our oil and natural gas properties and the oil and gas properties of our wholly owned subsidiaries. The borrowing base is subject to further adjustments for asset dispositions, material title deficiencies, certain terminations of hedge agreements and issuances of permitted additional indebtedness. As of June 8, 2022, the last date of redetermination, our borrowing base was $165 million.

Redetermination of the borrowing base under the Credit Facility is based primarily on reserve reports that reflect commodity prices at such time and occurs semi-annually, in March and September, as well as upon requested interim redeterminations by the lenders at their sole discretion. We also have the right to request additional borrowing base redeterminations each year at our discretion. Significant declines in commodity prices may result in a decrease in the borrowing base. These borrowing base declines can be offset by any commodity price hedges we enter. Our next borrowing base redetermination is scheduled for September, 2022.

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

At our election, interest on borrowings under the Credit Facility is determined by reference to either the secured overnight financing rate ("*SOFR*") plus an applicable margin between 3.00% and 4.00% per annum (depending on the then-current level of borrowings under the Credit Facility) or the alternate base rate ("*ABR*") plus an applicable margin between 2.00% and 3.00% per annum (depending on the then-current level of borrowings under the Credit Facility). Interest is generally payable quarterly for loans bearing interest based on the ABR and at the end of the applicable interest period for loans bearing interest at SOFR. We are required to pay a commitment fee to the lenders under the Credit Facility, which accrues at a rate per annum of 0.5% on the average daily unused amount of the lesser of: (i) the maximum commitment amount of the lenders and (ii) the then-effective borrowing base. The weighted average interest rate on Credit Facility borrowings was 4.00% in 2021. The effective borrowing rate under our Credit Facility was 4.1% as of March 31, 2022.

We are required to maintain (i) a current ratio (the ratio of current assets to current liabilities) greater than 1.0, which for purposes of this definition includes availability under the Credit Facility but excludes the fair value of derivative instruments, and (ii) a ratio of total net debt-to-EBITDAX of not greater than 3.00 to 1.00. For purposes of the total net debt-to-EBITDAX ratio, total net debt is total debt for borrowed money (including capital leases and purchase money debt) minus unrestricted cash and cash equivalents on hand at such time (not exceeding $15.0 million in the aggregate), and EBITDAX includes Cross Timber's EBITDAX only to the extent of cash distributions received by us. For purposes of our Credit Facility, EBITDAX is defined to mean net income plus interest expense; income taxes paid; depreciation, depletion and amortization; exploration expenses, including workover expenses; non-cash charges including unrealized losses on derivative instruments; and any extraordinary ornon-recurring charges, minus any extraordinary or non-recurring income and any non-cash income including unrealized gains on derivative instruments. Furthermore, we only include realized hedge gains less realized hedge losses and the consolidated expenses of ours and our subsidiaries. We were in compliance with all financial and other covenants of the Credit Facility as of March 31, 2022 except the covenant regarding hedge volumes required as of March 31, 2022. We received a waiver for this exception in June 2022. We believe that we have a sufficient combination of resources and operating flexibility to ensure that we remain in compliance with our debt covenants for at least the next 12 months.

Our Credit Facility permits us to make distributions of 100% of our "Distributable Cash Flow" so long as so long as (i) at the time of any such distribution and immediately after giving effect thereto, no default, event of default or borrowing base deficiency has occurred and is continuing, (ii) the our ratio of total net debt-to-EBITDAX does not exceed 2.00 to 1.00 as of the last day of the fiscal quarter most recently ended for which our financial statements have been delivered (determined on a pro forma basis after giving effect to such distribution) and (iii) after giving effect to such distribution, there is at least 20% of total borrowings then available under our Credit Facility. For purposes of our Credit Facility, "Distributable Cash Flow" is defined, generally, to mean (a) our EBITDAX during each period of four consecutive quarters (a "rolling period"), minus the increase (or plus the decrease) in working capital from the previous rolling period minus (b) the sum of (i) capital expenditures paid in cash, (ii) cash interest expense, (iii) cash taxes paid, (iv) exploration expenses or costs paid in cash, (v) restricted payments made in cash (other than any prior distributions of Distributable Cash Flow) and (vi) to the extent not included in this clause (b) and otherwise added back in the calculation of EBITDAX, any other cash charge that reduces our earnings. The amount of Distributable Cash Flow with respect to any fiscal quarter is further reduced by all prior distributions of Distributable Cash Flow during the applicable rolling period.

Further, our Credit Facility requires us to hedge at most 90% of reasonably anticipated projected production and at least (a) 75% of reasonably anticipated projected production of proved developed producing reserves for the 12-month period following January 1, 2022 and (b) thereafter 50% of reasonably anticipated projected production of proved developed producing reserves for the 30-month period following the date of any hedging transaction. See Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement" for more information. However, as of any time, if the net leverage ratio (the ratio of total net debt-to-EBITDAX) is less than or equal to 1.0 to 1.0 and the cash and cash equivalents on hand are equal to or greater than 20% of the borrowing base then in effect, the minimum required hedge volume for month one through month 24 will be reduced to 50%; and the requirement to maintain a minimum required hedge volume for months 25 through month 30 shall be removed.

Contractual obligations and commitments

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

Derivative contracts

We have entered into derivative instruments to hedge our exposure to commodity price fluctuations. If market prices are higher than the contract prices when the cash settlement amount is calculated, we are required to pay the contract counterparties. As of December 31, 2021, the current liability related to such contracts was $6.5 million and the non-current liability was $0.1 million. Such payments will generally be funded by higher prices received from the sale of oil, NGLs and natural gas. For further information on derivative contracts, see Note 10 in the financial statements included elsewhere in this prospectus.

Asset retirement obligations

At December 31, 2021, we had accrued asset retirement obligations of $104.5 million inclusive of a current portion of $1.1 million. For further information on asset retirement obligations, see Note 8 in the financial statements included elsewhere in this prospectus.

Quantitative and Qualitative Disclosure About Market Risk

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

Commodity price risk

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

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

As of March 31, 2022, the fair market value of our oil, NGL and natural gas derivative contracts was a net liability of $82.4 million. Based upon our open commodity derivative positions at March 31, 2022, a hypothetical 10% change in the NYMEX WTI and Henry Hub prices, OPIS prices and basis prices would change our net oil, NGL and natural gas derivative liability by approximately $38.0 million, as follows:

(In millions)	**Fair Value at March 31, 2022**	**Hypothetical Price Increase or Decrease of 10%**
Derivative asset (liability) - Crude Oil	$ (42,854)	$ 19,873
Derivative asset (liability) - Natural Gas	$ (32,808)	$ 15,180
Derivative asset (liability) – Natural Gas Liquid	$ (6,714)	$ 2,989
Total	$ (82,376)	$ 38,042

The hypothetical change in fair value could be a gain or loss depending on whether prices increase or decrease. Please see “—Derivative Arrangements.”

Counterparty and customer credit risk

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

We sell oil, NGL and natural gas production to various types of customers. Credit is extended based on an evaluation of the customer’s financial condition and historical payment record. The future availability of a ready market for our production depends on numerous factors outside of our control, none of which can be predicted with certainty. For the year ended December 31, 2021, we had three customers that each accounted for more than 10% of total revenues. See "Business and Properties—Operations—Marketing and Customers." We do not believe the loss of any single purchaser would materially impact our operating results because oil, NGLs and natural gas are fungible products with well-established markets and numerous purchasers.

At December 31, 2021, we had commodity derivative contracts with counterparties. We are currently not required to provide collateral or other security to counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Additionally, we use master netting arrangements to minimize credit risk exposure. The creditworthiness of our counterparties is subject to our periodic review.

Interest rate risk

At March 31, 2022, we had $130.0 million of variable rate debt outstanding. Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $1.3 million per year. See "—Liquidity and Capital Resources—Revolving credit agreement."

Critical accounting policies and estimates

Our financial position and results of operations are significantly affected by accounting policies and estimates related to our oil and gas properties, proved reserves, asset retirement obligations and commodity prices and risk management, as summarized below. See Note 1 of the notes to the audited financial statements included elsewhere in this prospectus for an expanded discussion of our significant accounting policies and estimates made by management.

Property and equipment

A majority of the property costs reflected in the accompanying balance sheet are from the acquisition of proved properties. Successful drill well costs are transferred to proved properties generally within one month of the well completion date.

Depreciation, depletion and amortization (DD&A) of proved producing properties is computed on theunit-of- production method based on estimated proved oil and gas reserves. Repairs and maintenance are expensed, while renewals and betterments are generally capitalized.

If conditions indicate that proved properties may be impaired, the carrying value of property is compared to management's future estimatedpre-tax undiscounted cash flow from properties generally aggregated on a field-level basis. If impairment is necessary, the asset carrying value is written down to fair value, typically a discounted present value of estimated future cash flows. Cash flow pricing estimates are based on estimated reserves and production information and pricing assumptions that management believes are reasonable.

The impairment assessment process is primarily dependent upon the estimate of proved reserves. Any overstatement of estimated proved reserve quantities would result in an overstatement of estimated future net cash flows, which could result in an understated assessment of impairment. The subjectivity and risks associated with estimating proved reserves are discussed under "Oil and Natural Gas Reserves" below. Prediction of product prices is subjective since prices are largely dependent upon supply and demand resulting from global and national conditions generally beyond our control. However, management's assessment of product prices for purposes of impairment is consistent with that used in its business plans and investment decisions. While there is judgment involved in management's estimate of future product prices, the potential impact on impairment has not been significant recently since product prices have been substantially higher than our net acquisition and development costs per Boe. However, due to the significant decline in product prices as a result of the COVID-19 pandemic, we recognized a $134.1 million impairment on certain of our proved properties in 2020. Prior to 2020, our historical impairment of proved properties included $177.4 million of proved property impairments from 2014 through 2018. We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impracticable to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome.

Costs of retired, exchanged, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently.

Oil and natural gas reserves

Our proved oil and natural gas reserves are estimated by independent petroleum engineers. Reserve engineering is a subjective process that is dependent upon the quality of available data and the interpretation thereof, including evaluation and extrapolations of well flow rates and reservoir pressure. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production, subsequent to the date of an estimate, as well as economic factors such as changes in product prices, may justify revision of such estimates. Because proved reserves are required to be estimated using the 12-month average prices, estimated reserve quantities can be significantly impacted by changes in product prices.

Proved reserves, as defined by the Financial Accounting Standards Board ("*FASB*") and adopted by the SEC, are limited to known reservoirs that indicate economic producibility through actual production or conclusive formation tests, and generally cannot extend beyond the immediate adjoining undrilled portion. Although improved technology often can identify possible and probable reserves other than by drilling, under current SEC rules, these reserves cannot be estimated or disclosed.

DD&A of producing properties is computed on the unit-of-production method based on estimated proved oil and natural gas reserves. While total DD&A expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in timing of when DD&A expense is recognized. Downward revisions of proved reserves result in an acceleration of DD&A expense, while upward revisions tend to lower the rate of DD&A expense recognition. During 2021, net upward revisions to proved reserves on a Boe basis occurred, which will result in a decrease in DD&A expense per unit of 49% in 2022.

The standardized measure of discounted future net cash flows and changes in such cash flows, are prepared using assumptions required by FASB and the SEC. Such assumptions include 12-month average oil and natural gas prices, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures. Discounted future net cash flows are calculated using a 10% rate. Changes in any of these assumptions could have a significant impact on the standardized measure. Accordingly, the standardized measure does not represent management's estimated current market value of proved reserves.

Derivatives

We use derivatives to hedge against changes in cash flows related to product price and interest rate risks, as opposed to their use for trading purposes. We record 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.

We do not designate these derivative contracts as cash flow hedges. Changes in the fair value of commodity price and interest rate derivatives are recognized currently in earnings. Realized and unrealized gains and losses on commodity derivatives are recognized in oil, NGL and natural gas revenues, and realized and unrealized gains and losses on interest rate derivatives are recorded as adjustments to interest expense. Settlements of derivatives are included in cash flows from operating activities.

While our price risk management activities decrease the volatility of cash flows, they may obscure our reported financial condition. As required under GAAP, we record derivative financial instruments at their fair value, representing projected gains and losses to be realized upon settlement of these contracts in subsequent periods when related production occurs. These gains and losses are generally offset by increases and decreases in the market value of our proved reserves, which are not reflected in the financial statements.

See also "Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk" for the effect of price changes on derivative fair value gains and losses.

Asset retirement obligations

If the fair value for an asset retirement obligation can be reasonably estimated, the liability is recognized in the period when it is incurred. Oil and natural 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 the discount of the estimated liability is recorded as an expense in the income statement.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. For example, as we analyze actual plugging and abandonment information, we may revise our estimates of current costs, the assumed annual inflation of these costs and/or the assumed productive lives of our wells. Revisions to the asset retirement obligations are recorded with an offsetting change to producing properties, resulting in prospective changes to DD&A expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates.

Revenue recognition and gas balancing

Oil, NGL and natural gas 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 we expect to be entitled in exchange for the product.

Recent accounting pronouncements

A summary of recent accounting pronouncements and our assessment of any expected impact of these pronouncements if known is included in Note 1 to the audited condensed financial statements included elsewhere in this prospectus.

Internal controls and procedures

We are not currently required to comply with the SEC's rules implementing Section 404 of the Sarbanes- Oxley Act of 2002 and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC's rules implementing Section 302 of the Sarbanes-Oxley Act of 2002, which will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. Though we will be required to disclose material changes made to our internal controls and procedures on a quarterly basis, we will not be required to make our first annual assessment of our internal control over financial reporting pursuant to Section 404 until the year following our first annual report to be filed with the SEC. We have elected to avail ourselves of the provision of the JOBS Act that permits emerging growth companies to take advantage of an extended transition period to comply with new or revised accounting standards applicable to public companies. We will not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls over financial reporting until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act.

BUSINESS AND PROPERTIES

Business Overview

We are focused on the acquisition, development, optimization and exploitation of conventional oil, natural gas, and natural gas liquid reserves in North America. Our management team has significant industry experience acquiring and exploiting conventional oil and natural gas properties in multiple resource plays and basins. As a result of such experience, our operations focus primarily on enhancing the development and operation of producing properties through our concentration on efficiency and optimizing exploitation of current wells. Our current acreage positions are concentrated in the Permian Basin of West Texas and New Mexico, and the San Juan Basin of New Mexico and Colorado, each of which we believe is characterized by low geologic risk, low decline rates and high recoveries relative to drilling and completion costs.

We intend to make quarterly distributions on our common units of all our cash available for distribution at the end of each such quarter. We believe the low decline nature of our reserves and the relatively low-cost expense to maintain production combined with our zero to low leverage profile will allow us to make relatively consistent quarterly distributions. The amount of cash flow from operations available for distribution with respect to any quarter, however, will be dependent on the then-prevailing commodity prices. To mitigate the risk associated with volatile commodity prices and to further enhance the stability of our cash flow available for distributions, from time to time we may opportunistically hedge a portion of our production volumes at prices we deem attractive to mitigate our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales.

We seek to maintain a flat to low growth production profile through a combination oflow-risk development and exploitation of our existing properties, generally funded by cash flow from operating activities and future acquisitions of producing properties. We believe this will allow us to increase our reserves and production and, over time, to increase distributions to our unitholders. To date we have been successful in offsetting the natural decline in production from reservoir depletion through acquisitions and drilling. Historically, funding sources for our capital expenditures, including acquisitions, have included proceeds from bank borrowings, cash from our partners and cash flow from operating activities. Following this offering, we expect to continue to fund our capital expenditures primarily with cash flow generated by operating activities, but may use borrowings under our Credit Facility in connection with acquisitions in particular. Additionally, we may seek to issue additional equity securities from time to time as market conditions allow to facilitate future acquisitions. Our development budget is approximately $30.0 million for 2022 (of which $0.7 million has been incurred as of March 31, 2022) and approximately $30.0 million for 2023.

The members of our management team have on an average of 34 years' experience in the oil and gas industry and previously held executive roles at XTO. Our management team has successfully executed on a strategy of acquiring and exploiting long-lived and low decline assets for more than 30 years, completing hundreds of acquisitions totaling over $15 billion. Additionally, our Chief Executive Officer, Bob Simpson, has a greater than 45-year history in the oil and gas industry. Mr. Simpson founded Cross Timbers Oil company in 1986 (subsequently named XTO Energy) and served as Chief Executive Officer and Chairman over the life of the company, culminating with a sale to Exxon Corporation for $41 billion in 2009. Additionally our management team has collectively invested more than $500 million in us since our inception. We believe our management team has the experience, expertise and commitment to create significant value for our unitholders in the form of cash distributions combined with growth in revenues and production.

As of December 31, 2021, our assets consisted of approximately 846,000 gross (370,000 net) leasehold and mineral acres located primarily in the Permian Basin and San Juan Basin. As of December 31, 2021, our total estimated proved reserves were approximately 130 MMBoe, of which approximately 37% were oil and approximately 82% were proved developed, both on a Boe basis. In the first quarter of 2022, we produced an average of approximately 23,077 Boe/d, approximately 72% of which came from assets operated by us.

The following tables present our historical estimated oil and natural gas reserves and PV-10 as of December 31, 2021.

	Estimated Proved Reserves as of December 31, 2021 (1)			
	SEC Pricing Proved Developed Reserves (MBoe)(2)	**SEC Pricing Proved Reserves (MBoe)**	**NYMEX Pricing Proved Developed Reserves (MBoe)(3)**	**NYMEX Pricing Proved Reserves (MBoe)(3)**
Permian Basin	34,790.0	54,715.2	35,541.8	55,527.7
San Juan Basin	66,735.2	66,735.2	72,973.5	72,973.5
Other	4,986.1	8,357.5	5,546.5	8,917.9
Total	106,511.3	129,807.9	114,061.8	137,419.1

(1) Presented on an oil-equivalent basis using a conversion of six thousand cubic feet of natural gas to one stock tank barrel of oil. This conversion is based on energy equivalence and not on price or value equivalence.

(2) SEC pricing, as required by the rules and regulations of the SEC, is the unweighted arithmetic average of the first-day-of-the-month price for each month within such period using published benchmark oil and gas prices, unless prices are defined by contractual arrangements."

(3) Using NYMEX forward-month contract pricing in effect as of June 15, 2022. We have included this reserve sensitivity because we believe that the use of NYMEX forward-month prices provides investors with additional useful information about our reserves. For more information regarding our use of NYMEX Pricing, please see "—Summary of Reserve, Production and Operating Data—Summary of Reserves as of December 31, 2021 Based on NYMEX Pricing."

	Estimated PV-10 as of December 31, 2021 (4)			
(in millions)	**SEC Pricing Proved Developed PV-10(1)(2)**	**SEC Pricing Proved PV-10(1)**	**NYMEX Pricing Proved Developed PV-10(3)**	**NYMEX Pricing Proved PV-10(3)**
Permian Basin	$ 486.5	$ 718.9	$ 694.1	$ 984.2
San Juan Basin	$ 254.2	$ 254.2	$ 480.4	$ 480.4
Other	$ 31.5	$ 44.2	$ 59.3	$ 80.0
Total	$ 772.2	$ 1,017.3	$ 1,233.8	$ 1,544.6

(1) Presented on an oil-equivalent basis using a conversion of six thousand cubic feet of natural gas to one stock tank barrel of oil. This conversion is based on energy equivalence and not on price or value equivalence.

(2) SEC pricing, as required by the rules and regulations of the SEC, is the unweighted arithmetic average of the first-day-of-the-month price for each month within such period using published benchmark oil and gas prices, unless prices are defined by contractual arrangements."

(3) Using NYMEX forward-month contract pricing in effect as of June 15, 2022. We have included this reserve sensitivity because we believe that the use of NYMEX forward-month prices provides investors with additional useful information about our reserves. For more information regarding our use of NYMEX Pricing, please see "—Summary of Reserve, Production and Operating Data—Summary of Reserves as of December 31, 2021 Based on NYMEX Pricing."

(4) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions.

The following table summarizes information regarding our active well count and development locations included in our reserve report as of December 31, 2021.

	As of December 31, 2021									
	Active Oil and Natural Gas Wells		Active CO_2 Injection Wells		Conventional PUD Locations(1)		Recomplete Locations(2)		Workover Locations(3)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin	4,046	657.7	57	40.3	233	104.0	51	32.8	23	22.6
San Juan Basin	11,379	1,094.3	—	—	—	—	—	—	—	—
Other	3,012	88.4	—	—	4	1.8	—	—	—	—
Total	18,437	1,840.4	57	40.3	237	105.8	51	32.8	23	22.6

(1) Approximately 97% of our wells are drilled conventionally. However, from time to time a small number of wells are horizontally completed.
(2) Well locations we believe we can recomplete into another producing zone or zones.
(3) Well locations where we believe a currently completed zone can be improved or restored by performing remedial workovers.

Our Properties

Permian Basin

We acquired our initial 79,970 gross leasehold and mineral acres in the Permian Basin in 2012 and 2013. We subsequently acquired 11,929 additional gross leasehold acres through leasing and multiple bolt-on acquisitions. In November 2021, we acquired producing properties including 24,052 gross leasehold acres and a CO_2 processing plant in the Permian Basin within New Mexico and CO_2 assets in Colorado (the “Chevron Vacuum Acquisition”) from Chevron Corporation (“Chevron”). In December 2021, we acquired additional producing properties including 21,112 gross leasehold acres in the Permian Basin within Texas from Chevron (the “Chevron Andrews Parker Acquisition”). As of March 31, 2022, we had 79 (gross) active CO_2 injection wells. Production from our CO_2 wells was 15.5 MMcf/d during the first quarter of 2022.

The Permian Basin is one of the oldest and most prolific producing basins in North America, with proven reserves of over 12.1 billion barrels of oil and 49.9 trillion cubic feet of natural gas as of 2019 according to the U.S. Energy Information Administration (“EIA”). Consisting of approximately 75,000 square miles centered around Midland, Texas, the Permian spans across west Texas and southeast New Mexico. The Permian Basin has been a significant source of oil production in the United States since the 1920s and, according to the EIA, accounted for approximately 41% of all oil production and approximately 15% of all natural gas production in the United States as of December 31, 2021. As of March 31, 2022, 323 rigs were running in the Permian, representing 48% of all rigs running in the United States according to Baker Hughes rig count data. While horizontal development is the primary focus for many operators, there continues to be significant conventional oil and gas drilling throughout the Permian Basin. Through enhanced oil recovery methods such as CO_2 injection, operators like us are able to unlock incremental additional hydrocarbon production in these older, conventional assets at comparatively lower costs as compared to the drilling and completion costs of horizontal wells.

Our management team believes the development and exploitation of conventional assets in the Permian Basin is among the most economic oil and natural gas plays in the United States. Since completing our 2021 acquisitions, we have focused our efforts on returning wells to production as well as on other low-risk maintenance projects. As we gain a greater understanding of these recently acquired assets, we expect to increase our drilling and recompletion work. Substantially all of our acreage in the Permian Basin is held by production which means we do not have to drill any wells to maintain ownership of our leases. Based on current commodity prices, we expect to drill or participate in the drilling of approximately 20 gross wells in the Permian Basin during the remainder of 2022 and approximately 9 gross wells in 2023. We expect to recomplete 18 gross wells in the Permian Basin in 2022 and approximately 22 gross wells in 2023. We expect to return 25 gross wells to production in the Permian Basin in 2022 and 23 gross wells in 2023. As of December 31, 2021, our decline rate for our Permian Basin properties over the next 12 months is approximately 7%.

San Juan Basin

We acquired our initial 175,376 gross leasehold and mineral acres in the San Juan Basin in 2012 and 2013. We subsequently acquired 273,187 additional gross leasehold and mineral acres in June 2020.

The San Juan Basin covers approximately 7,500 square miles in northwestern New Mexico, southwestern Colorado, and parts of Utah and Arizona. Primarily producing natural gas, the San Juan Basin has multiple different formation targets including conventional and unconventional tight sands, coalbed methane and shale. The San Juan is one of the oldest producing basins in the United States, with the first conventional natural gas well was drilled in 1921. With the discovery and development of coalbed methane reserves, the San Juan Basin was one of the most prolific natural gas basins in the United States in the 1980s and 1990s. Development activity within the San Juan Basin continued at a significant pace until 2008. With the collapse of commodity prices in 2007, development activity dropped to a very low rate, falling from approximately 40 drilling rigs into 2007 to less than five rigs by 2012. More recently, however, activity within the San Juan Basin has picked up through continued exploration of the unconventional Mancos Shale play. In 2016, the United States Geological Survey (“USGS”) estimated that there were 66.3 trillion cubic feet of recoverable natural gas in the Mancos Shale, which is a forty-fold increase from the 1.6 trillion cubic feet of recoverable natural gas estimated by USGS in 2003.

Our San Juan acreage includes substantial, predictable, low-decline natural gas production that provides for relatively stable cash flows. As of December 31, 2021, our decline rate for our San Juan Basin properties over the next 12 months is approximately 10%. Our existing production comes from primarily coalbed methane wells, in which we own 363,358 gross acres. Substantially all of our acreage in the San Juan Basin is held by production. Additionally, we own 85,205 gross acres in New Mexico in the Mancos Shale. We believe our Mancos Shale properties offer us significant potential upside that is held by production.

Based on current commodity prices, we expect to drill or participate in the drilling of approximately 13 gross wells in the San Juan Basin during the remainder of 2022 and approximately 4 gross wells in 2023. We do not expect to recomplete any gross wells in the San Juan Basin in 2022 and 2023. We expect to return 10 gross wells to production in the San Juan Basin in 2022 but none in 2023.

For the three months ended March 31, 2022, our consolidated revenues were derived 50% from oil revenues, 38% from natural gas revenues and 12% from NGL revenues, in each case excluding the unrealized effects of our commodity derivative contracts. After giving effect to unrealized commodity derivative contracts, our revenues were derived 27% from oil revenues, 106% from natural gas revenues and (33)% from NGL. For the three months ended March 31, 2022, our total average production was 23,077 Boe/d (approximately 25% oil, 61% natural gas, and 14% NGLs). Over the same period, our average production in the Permian Basin was 6,673 Boe/d (approximately 85% oil, 4% natural gas, and 11% NGLs) and our average production in the San Juan Basin was 14,962 Boe/d (approximately 1% oil, 82% natural gas, and 17% NGLs).

Development Plan and Capital Budget

Historically, our business plan has focused on acquiring and then exploiting producing assets. Funding sources for our acquisitions have included proceeds from bank borrowings, cash from our partners and cash flow from operating activities. Our development budget is approximately $30.0 million for 2022 (of which $ 0.7 million has been incurred as of March 31, 2022) and approximately $30.0 million for 2023. Much of our development time and capital is spent on workovers, recompletions and field optimizations of existing assets. We expect to use the additional information derived from this exploitation to inform our decisions about additional drilling opportunities to pursue, either in recently acquired assets or new acquisitions. However, over the next 24 months we anticipate approximately half of our development activity will be focused on drilling new wells, virtually all of which we expect to be conventional, vertical wells.

We expect to allocate most of our remaining 2022 budget and the majority of our 2023 budget to projects focused on enhancing existing production. Based on current commodity prices and our drilling success rate to date, we expect to be able to fund our 2022 and 2023 capital development programs from cash flow from operations and the net proceeds of this offering. We increased our 2021 capital program to $8.1 million compared to $5.5 million in 2020, primarily in response to the improved oil price environment and the improving global and national economic environment.

During 2021 we drilled 4 wells in the Permian Basin and 6 wells in the San Juan Basin. Additionally, during 2021 we recompleted 6 wells in the Permian Basin and 6 wells in the San Juan Basin.

During 2022, we expect to spend approximately $20 million to drill 33 gross wells (18 net wells) and related equipment, $4 million on recompletions of existing wells and $6 million on remedial workovers and other maintenance projects. We expect to spend approximately $20 million in the Permian Basin and approximately $10 million in the San Juan Basin in 2022.

Our Business Strategies

Our primary business objective is to generate relatively consitent cash flow to enable us to make quarterly cash distributions from our available cash to our unitholders and, over time, to increase our quarterly cash distributions. To achieve our objective, we intend to execute the following business strategies:

- **Focus on long-lived, low decline conventional assets.** We believe that by focusing on the exploitation of our existing assets, we can maintain current production using a portion of our operating cash flow, while utilizing the remainder of our operating cash flow to acquire additional assets to exploit and make distributions to our unitholders.

- **Maximize ultimate hydrocarbon recovery from our assets through enhancement and optimization of producing properties.** We continuously seek efficiencies in our drilling, completion and production techniques to optimize ultimate resource recoveries, rates of return and cash flows. We will continue to work to unlock additional value and will allocate capital towards next generation technologies where applicable. In addition, we intend to take advantage of under-development in basins where we operate by expanding our geologic investigation of additional producing horizons on our acreage and adjacent acreage. We seek to expand our development beyond our known productive areas to add reserves to our inventory at attractive all-in costs.

- **Focus on making cash distributions to, and providing long term value for, our unitholders.** Our primary goal is to maximize investor returns through cash distributions and flat to low growth. We intend to grow production and acreage over time, but our primary focus will be providing relatively consistent quarterly cash distributions from our available cash to our unitholders and increasing the long-term value of our common units.

- **Maintain financial flexibility with a conservative capital structure and ample liquidity.** We intend to conduct our operations primarily through cash flow generated from operations with a focus on maintaining a disciplined balance sheet with little to no outstanding debt. Due to our strong operating cash flows and liquidity, we have substantial flexibility to fund our capital budget and to potentially accelerate our drilling program as conditions warrant. Our focus is on the economic extraction of hydrocarbons while maintaining a prudent leverage ratio and strong liquidity profile. Although we may use leverage to make accretive acquisitions, we will do so with the long-term goal of remaining substantially debt free. Further, we expect that our hedging strategy will reduce our exposure to commodity price volatility.

- **Execute attractive acquisitions and optimize assets through effective integration.** Our management team has a history of successfully identifying, acquiring and optimizing assets over the past three decades. We believe our acreage positions in the Permian Basin and San Juan Basin provide opportunities to increase production and reserves through the implementation of mechanical and operational improvements, workovers, behind-pipe completions, secondary and tertiary recovery operations, new development wells and other development activities. We plan to use the expertise of our management team to strategically acquire properties that complement our operations.

Our Strengths

We believe that the following strengths will allow us to successfully execute our business strategies:

- **Experienced and personally invested management team with an extensive track record of value creation.** We believe our management team's significant industry experience is distinguishing competitive advantage. The members of our management team have an average of 34 years' experience in the oil and gas industry and have previously held executive roles at XTO. Our management team has successfully executed on a strategy of acquiring and exploiting long-lived and low decline assets for more than 30 years. Members of our management team have collectively personally invested more than $500 million in us since our inception.

- **Stable, long-lived, conventional asset base with low production decline rates.** The majority of our interests are in properties that have produced oil and natural gas for decades. As a result, the geology and reservoir characteristics are well understood, and new development well results are generally predictable, repeatable and present lower risk than unconventional resource plays. Our assets are characterized by long-lived reserves with low production decline rates, a stable development cost structure and low-geologic risk developmental drilling opportunities with predictable production profiles. For example, as of December 31, 2021, our decline rate over the next twelve months is approximately 9%.

- **Ability to source, integrate and optimize acquisitions.** Our management team has demonstrated the ability to source and integrate acquisitions of various sizes. While at XTO, our management team completed hundreds of acquisitions for over $15 billion in consideration and successfully integrated such acquisitions, ultimately driving significant returns for shareholders. We have successfully drawn on this experience to identify and complete multiple acquisitions to establish our anchor positions in the Permian Basin and San Juan Basin, including our recent Chevron Acquisitions. We expect that our expertise in sourcing and completing acquisitions will allow us to successfully execute additional bolt-on acquisitions in our existing operating areas and, if and when appropriate, additional opportunistic acquisitions.

- **Conservatively capitalized balance sheet, strong liquidity profile and financial flexibility.** We have a strong and conservative financial position that allows us to effectively allocate capital and grow our reserves and production. Due to the significant existing vertical production and the predictable low-decline profiles associated with our existing production, our business generates significant operating cash flows. After this offering, we expect to have little to no debt and substantial liquidity, which will provide us with further financial flexibility to fund our capital expenditures and grow production and reserves as part of our existing strategic plan. We may also opportunistically hedge to protect our future operating cash flows from volatility in commodity prices.

Oil, Natural Gas and NGL Data

Reserves

Summary of Oil, Natural Gas and NGL Reserves. The following table presents our estimated net proved oil, natural gas and NGL reserves as of December 31, 2021. The reserve estimates presented in the table below are based on reports prepared by Cawley, Gillespie & Associates, our independent petroleum engineers, which reports were prepared in accordance with current SEC rules and regulations regarding oil and natural gas reserve reporting.

	As of December 31, 2021(1)
Proved Reserves:	
Oil (MBbls)	48,570.8
NGLs (MBbls)	18,024.5
Natural gas (MMcf)	379,275.9
Total Proved Reserves (MBoe)	129,807.9
Standardized Measure (in millions)	$ 986.6
PV-10 (in millions)(2)	$ 1,017.3
Proved Developed Reserves:	
Oil (MBbls)	30,207.9
NGLs (MBbls)	17,434.2
Natural gas (MMcf)	353,214.9
Total Proved Developed Reserves (MBoe)	106,511.3
PV-10 (in millions)(2)	$ 772.2
Proved Undeveloped Reserves:	
Oil (MBbls)	18,362.9
NGLs (MBbls)	590.3
Natural gas (MMcf)	26,061.0
Total Proved Undeveloped Reserves (MBoe)	23,296.6
PV-10 (in millions)(2)	$ 245.1

(1) Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC regulations. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $66.56 per barrel for oil and $3.60 per MMBTU for natural gas at December 31, 2021. The base prices were based upon Henry Hub and WTI-Cushing spot prices, respectively. These base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these net adjustments, the net realized prices for the SEC price case over the life of the proved properties was estimated to be $64.76 per barrel for oil, $19.62 per barrel for NGLs and $2.31 per Mcf for natural gas for the year ended December 31, 2021.

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Our PV-10 has historically been computed on the same basis as our standardized measure of discounted future net cash flows ("Standardized Measure"), the most comparable measure under GAAP, but does not include a provision for either future well abandonment costs or the Texas gross margin tax. PV-10 is not a financial measure calculated or presented in accordance with GAAP and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of either well abandonment costs or income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

The following table presents our estimated net proved oil, natural gas and NGL reserves as of December 31, 2021 using average annual NYMEX forward-month contract pricing in effect as of June 15, 2022 ("NYMEX Pricing") but is otherwise presented on the same basis as the reserve information prepared in accordance with SEC regulations. We believe that the use of NYMEX forward-month prices provides investors with additional useful information about our reserves, as the NYMEX forward-month prices are based on a market-based expectation of oil and natural gas prices as of a certain date. NYMEX forward-month prices are not necessarily a projection of future oil and natural gas prices. Investors should consider NYMEX forward-month prices in addition to, and not as a substitute for, SEC prices, when considering our reserves of oil, natural gas and NGLs.

	As of December 31, 2021(1)
Proved Reserves:	
Oil (MBbls)	49,269.0
NGLs (MBbls)	19,334.8
Natural gas (MMcf)	412,891.8
Total Proved Reserves (MBoe)	137,419.1
PV-10(2)	$ 1,544.6
Proved Developed Reserves:	
Oil (MBbls)	30,853.6
NGLs (MBbls)	18,739.9
Natural gas (MMcf)	386,809.7
Total Proved Developed Reserves (MBoe)	114,061.8
PV-10(2)	$ 1,233.8
Proved Undeveloped Reserves:	
Oil (MBbls)	18,415.4
NGLs (MBbls)	594.9
Natural gas (MMcf)	26,082.1
Total Proved Undeveloped Reserves (MBoe)	23,357.3
PV-10(2)	$ 310.8

(1) The NYMEX futures prices as of June 15, 2022 used to prepare our reserve report are shown in the following table. These base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these net adjustments, the net realized prices for the NYMEX futures price case over the life of the proved properties was estimated to be $73.63 per barrel for oil, $21.47 per barrel for NGLs and $3.63 per Mcf for natural gas.

	2022	2023	2024	2025	2026	Thereafter
Natural gas price (per MMBtu)	$ 7.35	$ 6.12	$ 5.19	$ 4.87	$ 4.78	$ 4.78
Oil price (per Bbl)	$ 107.49	$ 94.37	$ 84.30	$ 76.80	$ 71.42	$ 71.42

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Our PV-10 has historically been computed on the same basis as our Standardized Measure, the most comparable measure under GAAP, but does not include a provision for either future well abandonment costs or the Texas gross margin tax. PV-10 is not a financial measure calculated or presented in accordance with GAAP and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of either well abandonment costs or income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair

market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

Additional information regarding our proved reserves and estimated future cash flows therefrom can be found in the notes to our financial statements included elsewhere in this prospectus and in the reserve reports prepared by Cawley, Gillespie & Associates that are filed as exhibits to the registration statement of which this prospectus forms a part.

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2021 included in this prospectus are based on evaluations prepared by the independent petroleum engineering firm of Cawley, Gillespie & Associates in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering similar resources.

Under SEC rules, proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. If deterministic methods are used, the term “reasonable certainty” implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. If probabilistic methods are used, there should at least be a 90% probability that the quantities actually recovered will equal or exceed the estimate. The technical and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, well-test data, production data (including flow rates), well data (including lateral lengths), historical price and cost information, and property ownership interests. Our independent reserve engineers use this technical data, together with standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy. The proved developed reserves and estimated ultimate recoveries (“EURs”) per well are estimated using performance analysis and volumetric analysis. The estimates of the proved developed reserves and EURs for each developed well are used to estimate the proved undeveloped reserves for each proved undeveloped location (utilizing type curves, statistical analysis, and analogy). All of our proved undeveloped reserves as of December 31, 2021, relate to locations that are one offset away from an existing well.

Internal Controls

Our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their preparation of reserve estimates. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil, natural gas and NGLs that are ultimately recovered. See "Risk Factors—Reserve estimates depend on many assumptions that may ultimately be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves" for more information. The reserves engineering group is responsible for the internal review of reserve estimates and includes Brandon Hudson, our Manager—Reservoir Engineering. The Reservoir Engineering Manager is primarily responsible for overseeing the preparation of our reserve estimates and has more than 15 years of experience as a reserve engineer. The reserves engineering group is independent of any of our operating areas. The Reservoir Engineering Manager is directly responsible for overseeing the reserves engineering group. The reserves engineering group reviews the estimates with our third-party petroleum consultants, Cawley, Gillespie & Associates, an independent petroleum engineering firm.

Cawley, Gillespie & Associates is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 60 years. The lead evaluator that prepared the reserve report was W. Todd Brooker, P.E., President at Cawley Gillespie. Mr. Brooker has been a Petroleum Consultant at Cawley, Gillespie & Associates since 1992 and became President in 2017. He graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum Engineering. Mr. Brooker is a State of Texas Licensed Professional Engineer (License #83462) and a member of the Society of Petroleum Evaluation Engineers (SPEE) and the Society of Petroleum Engineers (SPE). Mr. Brooker meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; Mr. Brooker is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2021, our proved undeveloped reserves were composed of 18,362.9 MBbls of oil, and 590.3 MBbls of NGLs and 26,061.0 MMcf of natural gas for a total of 23,296.6 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs, for the year ended December 31, 2021 (in MBoe):

Balance, December 31, 2020	**13,946.4**
Purchases of reserves	9,089.5
Revisions of previous estimates	271.1
Transfers to proved developed	(10.4)
Balance, December 31, 2021	**23,296.6**

Revisions of previous estimates of 271.1 MBoe during the year ended December 31, 2021 resulted primarily from higher commodity prices.

We converted 10.4 Mboe of any proved undeveloped reserves into proved developed reserves in 2021. Costs incurred relating to the development of oil and natural gas reserves were $8.1 million during the year ended December 31, 2021.

We drilled or participated in the drilling of 4 gross wells in the Permian Basin during 2021. We expect to drill or participate in the drilling of approximately 20 and 9 gross wells in the Permian Basin during 2022 and 2023, respectively. In addition, we participated in the drilling of 6 gross wells in the San Juan Basin during 2021. We expect to participate in the drilling of approximately 13 and 4 gross wells in the San Juan Basin during 2022 and 2023, respectively.

All of our PUD drilling locations are scheduled to be drilled within seven years of December 31, 2021. We anticipate drilling and completing or participating in the drilling and completion of approximately 22, 51 and 48 PUD locations during 2022, 2023 and 2024, respectively. These PUD locations relate to 7.7 MMboe of PUD reserves. Our estimated future development costs relating to the development of our PUDs at December 31, 2021 were projected to be approximately $18.7 million in 2022, $39.9 million in 2023, and $40.6 million in 2024. We expect that the substantial cash flow generated by our existing wells, in addition to availability under our Credit Agreement and the proceeds of this offering, will be sufficient to fund our drilling program, maintenance capital expenditures and PUD conversion into proved developed reserves in accordance with our development schedule. Please see “Risk Factors—Risks Related to Our Business and the Oil, Natural Gas and NGL Industry—Reserve estimates depend on many assumptions that may ultimately be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.”

Natural Gas, Oil and NGL Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding our production and operating data for the periods indicated.

Production data:

Sales:

	Year Ended December 31,		Three Months Ended March 31,	
	2020	**2021**	**2021**	**2022**
Permian Basin				
Natural gas sales (MMcf)	635	507	129	159
Natural gas liquids sales (MBbl)	77	81	20	67
Oil and condensate sales (MBbl)	897	985	184	507
Total (MMboe)	1,080	1,150	226	601
Total (MMboe/d)	3	3	3	7
San Juan				
Natural gas sales (MMcf)	18,415	26,796	6,391	6,640
Natural gas liquids sales (MBbl)	772	995	222	232
Oil and condensate sales (MBbl)	34	35	6	8
Total (MMboe)	3,875	5,496	1,293	1,347
Total (MMboe/d)	11	15	14	15
Other				
Natural gas sales (MMcf)	3,081	3,287	986	751
Natural gas liquids sales (MBbl)	11	13	1	2
Oil and condensate sales (MBbl)	9	13	1	2
Total (MMboe)	534	574	167	129
Total (MMboe/d)	1	2	2	1
Total (MMboe)	5,489	7,220	1,686	2,077

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Average realized sales prices:

	Year Ended December 31,		Three Months Ended March 31,	
	2020	2021	2021	2022
Permian Basin				
Natural gas excluding effects of derivatives (per Mcf)	$ 1.27	$ 3.94	$ 2.52	$ 4.48
Natural gas liquids excluding effects of derivatives (per Bbl)	$ 12.62	$ 32.50	$ 23.18	$ 53.71
Oil and condensate excluding effects of derivatives (per Bbl)	$ 37.30	$ 67.93	$ 57.27	$ 94.00
San Juan				
Natural gas excluding effects of derivatives (per Mcf)	$ 1.90	$ 4.03	$ 4.47	$ 4.91
Natural gas liquids excluding effects of derivatives (per Bbl)	$ 9.78	$ 24.59	$ 19.28	$ 33.90
Oil and condensate excluding effects of derivatives (per Bbl)	$ 31.69	$ 55.73	$ 44.41	$ 70.75
Other				
Natural gas excluding effects of derivatives (per Mcf)	$ 2.01	$ 3.76	$ 3.12	$ 4.97
Natural gas liquids excluding effects of derivatives (per Bbl)	$ 12.01	$ 23.26	$ 22.55	$ 36.52
Oil and condensate excluding effects of derivatives (per Bbl)	$ 38.75	$ 59.30	$ 51.89	$ 83.50
($ / Boe)	$ 15.57	$ 30.38	$ 28.25	$ 46.69

Expense per Boe:

	Year Ended December 31,		Three Months Ended March 31,	
	2020	2021	2021	2022
Permian Basin				
Production	$ 25.23	$ 30.65	$ 31.71	$ 26.84
Taxes, transportation, and other	$ 3.95	$ 6.89	$ 5.73	$ 14.35
Depreciation, depletion, and amortization	$ 25.20	$ 19.76	$ 21.92	$ 11.93
San Juan				
Production	$ 4.82	$ 5.62	$ 5.02	$ 5.96
Taxes, transportation, and other	$ 5.40	$ 8.67	$ 8.21	$ 10.61
Depreciation, depletion, and amortization	$ 1.97	$ 2.03	$ 1.99	$ 1.17
Other				
Production	$ 6.02	$ 5.39	$ 3.86	$ 6.86
Taxes, transportation, and other	$ 4.31	$ 4.33	$ 4.75	$ 4.51
Depreciation, depletion, and amortization	$ 14.02	$ 10.42	$ 10.20	$ 8.02

Productive Wells

As of March 31, 2022, the Company owned interests in the following number of productive wells:

	Oil Wells	Gas Wells	Total
Permian Basin			
Gross	3,923.0	123.0	4,046.0
Net	645.9	11.8	657.7
San Juan			
Gross	30.0	11,349.0	11,379.0
Net	—	1,094.3	1,094.3
Other			
Gross	729.0	2,283.0	3,012.0
Net	—	88.4	88.4
Total			
Gross	4,682.0	13,755	18,437
Net	645.9	1,194.5	1,840.4

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2021 relating to our developed and undeveloped acreage. Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned. A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	136,903	73,256	160	80	137,063	73,336
San Juan Basin	445,271	245,545	3,292	2,496	448,563	248,041
Other	260,288	48,250	—	—	260,288	48,250
Total	842,462	367,051	3,452	2,576	845,914	369,627

Drilling Results

The following table sets forth the results of our drilling activity for the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return.

	Years Ended December 31,			
	2020		2021	
	Gross	Net	Gross	Net
Development wells:				
Completed as:				
Gas wells	—	—	4	0.9
Oil wells	4	0.3	6	0.6
Non-productive	—	—	—	—
Total	4	0.3	10	1.5
Exploratory wells:				
Completed as:				
Gas wells	—	—	—	—
Oil wells	—	—	—	—
Non-productive	—	—	—	—
Total	—	—	—	—
Total	**4**	**0.3**	**10**	**1.5**

(1) These four wells include two gross (0.0 net) wells drilled by other operators during the year ended December 31, 2020 in which we elected not to participate.
(2) These 10 wells include two gross (0.0 net) wells drilled by other operators during the year ended December 31, 2021 in which we elected not to participate.

The following table sets forth information regarding our drilling activities as of March 31, 2022, including with respect to wells awaiting completion, undergoing completion activities and which we have begun drilling subsequent to March 31, 2022.

	Permian Basin		San Juan Basin	
	Gross	Net	Gross	Net
Drilling	—	—	3	0.0
Awaiting completion	—	—	—	—
Undergoing completion activities	—	—	—	—
Drilling begun subsequent to March 31, 2022	3	0.5	4	0.1

Operations

General

We operated wells responsible for approximately 66% of our production for the year ended December 31, 2020 and 68% for the year ended December 31, 2021. As operator, we design and manage the development, recompletion or workover for all of the wells we operate and supervise operation and maintenance activities on a day-to-day basis. We do not own the drilling rigs or other oil field services equipment used for drilling or maintenance on the properties we operate.

Independent contractors engaged by us provide a portion of the equipment and personnel associated with these activities. We currently engage independent contractors who are engineers and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Virtually all of our non-operated wells are managed by third-party operators who are typically independent oil and natural gas companies. Maverick Natural Resources Corporation, Occidental Petroleum Corporation and Jo Mill Oil Company are the operators on more than 50% of our non-operated acreage in the Permian Basin.

Our assets include a 50% interest in Cross Timbers Energy. The XTO Entities collectively own the remaining 50% interest in Cross Timbers. We account for our undivided interest in our investment in Cross Timbers using the proportionate consolidation method, pursuant to which we consolidate our proportionate share of assets (including reserves), liabilities, revenues and expenses of the joint venture. For the year ended December 31, 2021, Cross Timbers represents approximately 41% of our revenues and approximately 35% of our proved reserves, on a proportional ownership basis, with assets primarily located in the Permian Basin of Texas and New Mexico and the San Juan Basin of New Mexico and Colorado.

In accordance with the limited liability company agreement governing Cross Timbers (the “JV LLCA”), Cross Timbers is managed by us and governed by a member management committee comprised of six members, three of whom are appointed by us and three of whom are appointed by the XTO Entities. The JV LLCA requires that certain matters, including certain material contracts or acquisitions, mergers, sale of substantially all assets or other change of control transactions, and transfers of our interest to a third party, be approved by unanimous consent of the voting members of the management committee and therefore require the approval of the XTO Entities. While Cross Timbers is required to distribute all net cash flow to the members pro rata in accordance with their respective membership interests on a quarterly basis pursuant to the JV LLCA, we do not have sole control of the amount of distributions to be made by Cross Timbers.

Cross Timbers is also a party to an operating and services agreement with us pursuant to which we provide all administrative services and conduct operations that are necessary or proper for the development, operation, protection and maintenance of the assets held by Cross Timbers in exchange for a management fee. We earned management fees from Cross Timbers of $1.5 million for the three months ended March 31, 2022, $6.1 million for the year ended December 31, 2021, and $6.4 million for the year ended December 31, 2020.

Marketing and Customers

We market the majority of the natural gas, NGL, crude oil and condensate production from the properties on which we operate. We also market products produced by third party working interest owners who participate in various wells or production units on which we operate. We proportionately pay our royalty owners from the sales attributable to our working interest. Production from our properties is marketed using methods that are consistent with industry practice. Purchasers of our production are selected on the basis of price, credit quality and service reliability. Sales prices are negotiated based on factors normally considered in the industry, such as index or spot price, differentials based on the distance from tailgate of processing plants to end users, commodity quality and prevailing supply and demand conditions. Market volatility due to fluctuating weather conditions, international political developments, overall energy supply and demand, economic growth rates and other factors in the United States and worldwide have had, and will continue to have, a significant effect on energy prices.

We sell the majority of our production under arm's length contracts with terms of 12 months or less, including on amonth-to-month basis, to a relatively small number of customers, as is customary in our industry. We generally sell natural gas, NGL, crude oil and condensate production through production sale agreements with customary terms and conditions for the oil and natural gas industry at prevailing market prices, adjusted for quality, transportation fees, fractionation fees, regional price differentials, and, in the case of natural gas, energy content. Typically, our sales contracts are based on pricing provisions that are tied to a market index or postings. None of our contracts have minimum volume commitments or dedications. We have no commitments to deliver a fixed or determinable quantity of our oil or natural gas production in the near future under our existing contracts.

For the year ended December 31, 2021, Phillips 66 Company, Tenaska Marketing andEco-Energy, Inc. accounted for more than 40% of our total revenues, excluding the impact of our commodity derivatives. For the year ended December 31, 2020, Phillips 66 Company and Tenaska Marketing accounted for more than 40% of our total revenues, excluding the impact of our commodity derivatives. No other purchaser accounted for more than 10% of our total revenue during such period. We do not have long-term contracts with our customers but rather we sell the substantial majority of our production under arm's length contracts with terms of 12 months or less, including on a combined basis, to a relatively small number of customers. The loss of any such purchaser could materially adversely affect our financial condition, results of operations and ability to make distributions to our unitholders. However, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any such purchaser would not have a material adverse effect on our financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers. For more details, see "Risk Factors—Risks Related to Our Business and the Oil, Natural Gas and NGL Industry—We depend upon several significant purchasers for the sale of most of our oil, natural gas and NGL production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce."

Hedging

Our policy is to hedge opportunistically a portion of our production at commodity prices management deems attractive to mitigate our exposure to lower commodity prices. Under our Credit Facility, we are allowed to hedge at most 90% of reasonably anticipated projected production, but we are required to hedge at least (a) 75% of reasonably anticipated projected production of proved developed producing reserves for the 12-month period following January 1, 2022 and (b) thereafter 50% of reasonably anticipated projected production of proved developed producing reserves for the 30-month period following the date of any hedging transaction. However, as of any time, if the net leverage ratio (the ratio of total net debt-to-EBITDAX) is less than or equal to 1.0 to 1.0 and the cash and cash equivalents on hand are equal to or greater than 20% of the borrowing base then in effect, the minimum required hedge volume for month one through month 24 will be reduced to 50%. See Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving credit agreement" for more information. While there is a risk that we may not be able to realize the benefits of rising prices, we enter into hedging agreements because of the benefits of predictable, stable cash flows.

We enter futures contracts, energy swaps, swaptions and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We also enter costless price collars, which set a ceiling and floor price to hedge our exposure to price fluctuations on 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. For more details, see "Risk Factors—Risks Related to Our Business and the Oil, Natural Gas and NGL Industry—We use derivative instruments to economically hedge exposure to changes in commodity price and, as a result, are exposed to credit risk and market risk."

For a more detailed discussion of our hedging activities, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Quantitative and Qualitative Disclosure About Market Risk."

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in producing oil and natural gas properties, particularly during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

There is also competition between oil and natural gas producers and other industries producing energy and fuel and alternative technologies to reduce energy and fuel consumption. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the state and local jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Oil and Natural Gas Leases

The typical oil lease agreement covering our properties provides for the payment of royalties to the mineral owner for all hydrocarbons produced from any well drilled on the lease premises. The lessor royalties and other leasehold burdens on our properties range from less than 12.5% to 57.5%, resulting in a net revenue interest to us of 87.0% on average, on a 100% working interest basis. Based on the Standardized Measure, our value-weighted average net revenue interest on our properties was approximately 84.0%, on a 100% working interest basis, based on our December 31, 2021 reserve report. Substantially all of our leases are held by production and do not require continuous development.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct a cursory review of the title to the properties in connection with the acquisition of producing wells and/or additional acreage. Typically, that examination is limited to the seller's interest. At such time as we determine to conduct drilling operations, we administer a thorough title examination and perform curative work with respect to significant defects in title, prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects and/or other curative matters relative to those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant leases and, depending on the materiality of properties, we will review previously obtained title opinions, update title, and in most cases have new title opinions rendered by a licensed oil and gas attorney. Our oil and natural gas properties are subject to customary royalty and perhaps other interests, possible liens for current taxes and potentially other encumbrances which we believe do not materially interfere with the use of or affect our carrying value of the properties.

We believe that we hold satisfactory title to all of our material assets. Although title to these properties is subject to certain encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights of way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this prospectus.

Seasonality

Generally, but not always, the demand for oil and natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers also may impact this demand. In addition, pipelines, utilities, local distribution companies and industrial end users utilize oil and natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also impact the seasonality of demand. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

In addition, our exploration, exploitation and development activities and equipment could be adversely affected by extreme weather conditions, such as hurricanes or lighting storms, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. See "Risk Factors—Risks Related to the Oil, Natural Gas and NGL Industry and Our Business—Extreme weather conditions could adversely affect our ability to conduct drilling activities in the areas where we operate."

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Historically, our compliance costs have not had a material adverse effect on our results of operations; however, we are unable to predict the future costs or impact considered by Congress, the states, the FERC and the courts. We cannot predict when or whether any such proposals may become effective. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Regulation Affecting Production

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

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

Regulation Affecting Sales and Transportation of Commodities

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

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

The FERC regulates interstate natural gas pipeline transportation rates and service conditions. The FERC is continually proposing and implementing new rules and regulations affecting interstate transportation. The stated purpose of many of these regulatory changes is to ensure terms and conditions of interstate transportation service are not unduly discriminatory or unduly preferential, to promote competition among the various sectors of the natural gas industry and to promote market transparency. We do not believe that our drilling program will be affected by any such FERC action in a manner materially differently than other similarly situated natural gas producers.

In addition to the regulation of natural gas pipeline transportation, FERC has jurisdiction over the purchase or sale of natural gas or the purchase or sale of transportation services subject to FERC's jurisdiction pursuant to the EPAct 2005. Under the EPAct 2005, it is unlawful for "any entity," including producers such as us, that are otherwise not subject to FERC's jurisdiction under the NGA to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives FERC authority to impose civil penalties for violations of the NGA and the Natural Gas Policy Act of 1978 up to $1,388,496 per violation per day. The anti-manipulation rule applies to activities of otherwise non jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under FERC Order No. 704 (defined below).

In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order No. 704"). Under Order No. 704, any market participant, including a producer that engages in certain wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, must annually report such sales and purchases to FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to the formation of price indices. Not all types of natural gas sales are required to be reported on Form No. 552. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 is intended to increase the transparency of the wholesale natural gas markets and to assist FERC in monitoring those markets and in detecting market manipulation.

Through several issuances, FERC has signaled its intention of undertaking a "rigorous review" of reasonably foreseeable greenhouse gas ("GHG") emissions of new or expanded natural gas transportation facilities and their contribution to climate change, along with the enhanced consideration other factors such as project need, landowner impacts and environmental justice, in determining the benefits of a project and the significance of its environmental impacts. FERC considers project benefits and environmental impacts in determining whether to issue a certificate to construct a new project under the Natural Gas Act and in its environmental analysis required under the National Environmental Policy Act. On March 24, 2022, FERC announced that it was seeking comments on these draft proposed policies, which initially had been issued as guidance. If adopted, these policy changes may create delays in, and potentially affect the outcomes of, FERC's future assessments of the need for and environmental impacts of gas pipeline projects in determining whether a project is required by the present or future public convenience or necessity under the Natural Gas Act, which in turn may reduce the development of interstate natural gas pipeline projects and the future availability of pipeline capacity to transport our natural gas production.

The FERC also regulates rates and terms and conditions of service on interstate transportation of liquids, including NGLs, under the Interstate Commerce Act, as it existed on October 1, 1977 ("ICA"). Prices received from the sale of liquids may be affected by the cost of transporting those products to market. The ICA requires that certain interstate liquids pipelines maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

The rates charged by many interstate liquids pipelines are currently adjusted pursuant to an annual indexing methodology established and regulated by FERC, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning July 1, 2021, FERC established an annual index adjustment equal to the change in the producer price index for finished goods—0.21%. This adjustment is subject to review every five years. Under FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by obtaining market based rate authority (demonstrating the pipeline lacks market power), establishing rates by settlement with all existing shippers, or through a cost of service approach (if the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology). Increases in liquids transportation rates may result in lower revenue and cash flows for the Company.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity or for new shippers. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows. However, we believe that access to liquids pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

On February 17, 2022, FERC issued a Notice of Inquiry, seeking to explore oil pipeline capacity allocation issues that arise when anomalous conditions affect the demand for oil pipeline capacity and what actions FERC should consider to address those allocation issues. This proceeding was initiated in part by the impact of the COVID-19 pandemic on jet fuel shippers' ability to access capacity on oil pipelines using historic-based prorationing. However, the Notice of Inquiry seeks comments on the broader issue of diminished access to oil pipeline capacity during anomalous conditions. Rates for intrastate pipeline transportation of liquids are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. We believe that the regulation of liquids pipeline transportation rates will not affect our operations in any way that is materially different from the effects on our similarly situated competitors.

In addition to FERC's regulations, we are required to observe anti market manipulation laws with regard to our physical sales of energy commodities. In November 2009, the FTC issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to approximately $1,323,791 per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the CFTC to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of approximately $1,303,559 or triple the monetary gain to the person for each violation.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent federal, state and local laws and regulations governing occupational safety and health aspects of our operations, the discharge of materials into the environment and the protection of the environment and natural resources (including threatened and endangered species and their habitat). Numerous governmental entities, including the EPA and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions.

These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and on-going operations, such as requirements to close pits and plug abandoned wells; (v) apply specific health and safety criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, the occurrence of delays or restrictions in permitting or performance of projects, and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly well drilling, construction, completion or water management activities, or waste handling, storage transport, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. Continued compliance with existing requirements is not expected to materially affect us. However, there is no assurance that we will be able to remain in compliance in the future with such existing or any new laws and regulations or that such future compliance will not have a material adverse effect on our business and operating results.

In addition, governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political and regulatory risks in the United States, including climate change related pledges made by certain candidates elected to public office. President Biden has issued several executive orders focused on addressing climate change since taking office, including items that may impact the costs to produce, or demand for, oil and natural gas. Additionally, in November 2021, the Biden Administration released “The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050,” which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-carbon dioxide GHG emissions, such as methane and nitrous oxide. The Biden Administration is also considering revisions to the leasing and permitting programs for oil and natural gas development on federal lands.

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

Hazardous Substances and Wastes

The Resource Conservation and Recovery Act (“RCRA”), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to rules issued by the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of natural gas, if properly handled, are currently exempt from regulation as hazardous waste under RCRA and, instead, are regulated under RCRA’s less stringent non-hazardous waste provisions, state laws or other federal laws. However, it is possible that certain natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our as well as the oil and natural gas exploration and production industry’s costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. In the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes.

The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), also known as the Superfund law, and comparable state laws impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and former owners and operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We currently own, lease, or operate numerous properties that have been used for oil, natural gas and NGL exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off site locations, where such substances have been taken for treatment or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Federal Water Pollution Control Act, also known as the Clean Water Act ("CWA"), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of hazardous substances, into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In 2015, the EPA and the U.S. Army Corps of Engineers ("Corps") issued a final rule attempting to clarify the federal jurisdictional reach over waters of the United States ("WOTUS"). The rule has the potential to expand CWA jurisdiction to ephemeral waters found in generally arid regions of the United States. In January 2020, the EPA and Corps replaced the WOTUS rule with the narrower Navigable Waters Protection Rule, and litigation ensued. In August 2021, a federal judge struck down the Navigable Waters Protection Rule. Soon after, the Biden administration and the Corps announced that they have stopped enforcing the Navigable Waters Protection Rule nationwide and that they are reverting back to the 1986 WOTUS definition. In November 2021, the EPA and Corps issued prepublication notice of a proposed rule to revise the definition of "waters of the United States" to put back into place the pre-2015 definition, updated to reflect consideration of Supreme Court decisions, including the Supreme Court's April 2020 decision holding that, in certain cases, discharges from a point source to groundwater could fall within the scope of the CWA and require a permit. In January 2022, the Supreme Court agreed to hear a case regarding the jurisdictional reach of WOTUS. In addition to the recently reopened litigation over the rule in district courts, multiple states and environmental groups have challenged the suspension of the rule, and future implementation of the WOTUS rule is uncertain at this time. To the extent any final rule expands the federal jurisdictional reach over WOTUS, we could be subject to additional permitting obligations, which could lead to potential project delays and additional compliance costs.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 ("OPA"), which amends and augments the oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

Subsurface Injections

In the course of our operations, we produce water in addition to oil, natural gas and NGLs. Water that is not recycled may be disposed of in disposal wells, which inject the produced water into non-producing subsurface formations. Underground injection operations are regulated pursuant to the Underground Injection Control ("UIC") program established under the federal Safe Drinking Water Act ("SDWA") and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. A change in UIC disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of produced water and ultimately increase the cost of our operations. For example, in response to recent seismic events near belowground disposal wells used for the injection of natural gas related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such disposal wells. In response to these concerns, regulators in some states have adopted, and other states are considering adopting, additional requirements related to seismic safety. These seismic events have also led to an increase in tort lawsuits filed against exploration and production companies as well as the owners of underground injection wells. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability; however, these costs are commonly incurred by all oil and natural gas producers and we do not believe that the costs associated with the disposal of produced water will have a material adverse effect on our operations.

Air Emissions

The CAA and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance standards. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Recently, there has been increased regulation with respect to air emissions resulting from the oil and natural gas sector. For example, the EPA promulgated rules in 2012 under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and a separate set of requirements to address certain hazardous air pollutants frequently associated with oil and natural gas production and processing activities pursuant to the National Standards for Emission of Hazardous Air Pollutants ("NESHAPS") program. With regard to production activities, these final rules require, among other things, the reduction of volatile organic compound ("VOC") emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further requires that a subset of these selected wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels.

The EPA has also imposed increasingly stringent performance standards on oil and gas operations. In 2016, the EPA issued regulations under NSPS OOOOa that require operators to reduce methane and volatile organic compound ("VOC") emissions from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations. In November 2021, the EPA proposed a rule to further reduce methane and VOC emissions from new and existing sources in the oil and natural gas sector. The proposed rule would establish standards of performance for sources that commence construction, modification or reconstruction after the date the proposed rule is published in the Federal Register and would establish emissions guidelines, which will inform state plans to establish standards for existing sources. The EPA is currently seeking public comments on its proposal, which the EPA hopes to finalize by the end of 2022. Once finalized, the regulations are likely to be subject to legal challenge. Emissions guidelines will also need to be incorporated into the states' implementation plans, which will need to be approved by the EPA in individual rulemakings that could also be subject to legal challenge. State agencies have similarly imposed increasing restrictions on emissions from oil and gas operations. For example, in 2022, the New Mexico Environment Department adopted new regulations establishing emission reduction requirements for storage vessels, compressors, turbines, heaters, engines, dehydrators, pneumatic devices, produced water management units, and other equipment and processes. Increasingly stringent requirements on new oil and gas facilities, or the application of new requirements to existing facilities, could result in additional restrictions on operations and increased compliance costs, which could be significant.

The Bureau of Land Management (the "BLM") also finalized rules (the "BLM methane rule") in November 2016 that seek to limit methane emissions from exploration and production activities on federal lands by imposing limitations on venting and flaring of natural gas, as well as requirements for the implementation of leak detection and repair programs for certain processes and equipment. After attempts by the Trump administration to delay implementation of the BLM methane rule, and legal challenges both to the BLM methane rule and the delays, the BLM issued a final rule in September 2018 rescinding many of the provisions of the 2016 BLM methane rule, including the requirement to implement leak detection and repair programs, and imposing certain new requirements in a manner the BLM considered would reduce unnecessary compliance obligations on the industry. In July 2020 a federal district court in California vacated the 2018 rescission rule. BLM filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit; however, the federal district court in California entered a final judgment vacating the September 2018 rescission rule in October 2020. Separately, in October 2020, a federal district court judge in Wyoming vacated the 2016 rule. Environmental groups appealed the Wyoming decision in December 2020, and litigation is ongoing.

The EPA also finalized separate rules under the CAA in June 2016 regarding criteria for aggregating multiple sites into a single source for air quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities (such as tank batteries and compressor stations), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. In addition, in October 2015, the EPA issued a final rule under the CAA, lowering the NAAQS for ground level ozone from the current standard of 75 ppb for the current 8 hour primary and secondary ozone standards to 70 ppb for both standards, and completed attainment/non-attainment designations in July 2018. EPA reviewed the 2015 standards in 2020, but retained the standard without revision. Impacts associated with the 2015 standard vary by geographic location, but could include additional fees and more stringent permitting requirements, among other things. None of the counties in which we operate have been designated as non-attainment.

Compliance with one or more of these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant. In addition, our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and criminal enforcement actions.

Regulation of GHG Emissions (Climate Change)

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that typically will be established by state agencies. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from specified large, GHG emission sources in the United States, including certain onshore and offshore oil and natural gas production sources, which include certain of our operations. As discussed above, federal regulatory action with respect to GHG emissions from the oil and natural gas sector has focused on methane emissions; however, implementation of the federal methane rules is uncertain at this time.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, the current administration has highlighted addressing climate change as a priority and has issued several executive orders addressing climate change, including one that calls for substantial action, such as the increased use of zero-emission vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across government agencies and economic sectors. In the absence of federal climate legislation, a number of state and regional cap and trade programs have emerged that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. In addition, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. Although the United States had withdrawn from the Paris Agreement, President Biden has recommitted the United States and, in April 2021, announced a goal of reducing the United States’ emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered again in Glasgow at the 26th Conference to the Parties on the UN Framework Convention on Climate Change (“COP26”), during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-carbon dioxide GHGs. Relatedly, the United States and European Union jointly announced the launch of the “Global Methane Pledge,” which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including “all feasible reductions” in the energy sector.

Although it is not possible at this time to predict how new laws or regulations in the United States that may be adopted or issued to address GHG emissions would impact our business, any such future laws, regulations or legal requirements imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. In addition, increasing social attention to ESG matters and climate change has resulted in demands for action related to climate change and energy transition matters, such as promoting the use of substitutes to fossil fuel products, encouraging the divestment of fossil fuel equities, and pressuring lenders and other financial services companies to limit or curtail activities with fossil fuel companies. Initiatives to incentivize a shift away from fossil fuels could reduce demand for hydrocarbons, thereby reducing demand for our services and causing a material adverse effect on our earnings, cash flows and financial condition.

Litigation risks are also increasing as a number of entities have sought to bring suit against various oil and natural gas companies in state or federal court, alleging among other things, that such companies created public nuisances by producing fuels that contributed to climate change or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts.

Finally, it should be noted that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into targeted geological formations to fracture the surrounding rock and stimulate production. We engage in hydraulic fracturing as part of our operations currently and may continue to do so in the future.

Hydraulic fracturing is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA published final CAA regulations in 2012 and, more recently, in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting and separately published in June 2016 an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under certain limited circumstances.” Also, the BLM finalized rules in March 2015, establishing stringent standards relating to hydraulic fracturing on federal and American Indian lands. This rule was struck down by a Wyoming federal district court judge in June 2016 but was subsequently appealed by the BLM to the U.S. Circuit Court of Appeals for the Tenth Circuit. In September 2017, the Tenth Circuit issued a ruling to vacate this decision and dismiss the lawsuit challenging the rule in light of the BLM’s proposed rulemaking. In December 2017, BLM issued a final rule repealing the 2015 hydraulic fracturing rule. The BLM’s rescission of the rule was challenged by several environmental groups and states in the United States District Court for the Northern District of California. The United States District Court for the Northern District of California upheld the BLM’s rescission in a March 2020 decision.

From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Meanwhile, the regulation of hydraulic fracturing has continued at the state level. In the event that a new, federal level of legal restrictions relating to the hydraulic fracturing process is adopted in areas where we operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

Activities on Federal Lands

Oil and gas exploration, development and production activities on federal lands, including American Indian lands, are administered by the BLM. Operations on federal and tribal lands are frequently subject to permitting delays. Operations on these lands are also subject to NEPA. NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. We currently have exploration, development and production activities on federal lands and our proposed exploration, development and production activities are expected to include leasing of federal mineral interests, which will require the acquisition of governmental permits or authorizations that are subject to the requirements of NEPA. This process has the potential to delay or limit, or increase the cost of, the development of oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Moreover, depending on the mitigation strategies recommended in Environmental Assessments or Environmental Impact Statements, we could incur added costs, which may be substantial.

Moreover, the Biden administration’s January 2021 climate change executive order directed the Secretary of the Interior to pause new oil and natural gas leasing on public lands and in offshore waters pending completion of a comprehensive review of the federal permitting and leasing practices. In November 2021, the U.S. Department of the Interior released its “Report On The Federal Oil And Gas Leasing Program,” which assessed the current state of oil and gas leasing on federal lands and proposed several reforms, including raising royalty rates and implementing stricter standards for entities seeking to purchase oil and gas leases. In January 2022, a federal district court judge in Washington, D.C. vacated the results of the federal government’s Lease Sale 257, effectively canceling the sale, on the grounds that the federal government failed to consider foreign consumption of oil and natural gas from its GHG emissions analysis. In February 2022, a federal district court judge in Louisiana blocked the Biden Administration's method of calculating the social costs associated with GHGs, and specifically blocked federal agencies from considering the findings from the White House Interagency Working Group, which had been tasked with devising new metrics based on the Obama-era calculations. In response, also in February 2022, the Biden administration asked the court to stay the injunction, and announced that it would be suspending or delaying new federal oil and gas leases. The Biden administration resumed its federal leasing program in April 2022. These recent developments and the Biden administration's and certain federal courts' focus on the climate change impacts of federal projects could result in significant changes to the federal oil and gas leasing program in the future. Restrictions surrounding onshore drilling, onshore federal lease availability, and restrictions on the ability to obtain required permits, could have a material adverse impact on our operators and, in turn, our operations.

Endangered Species and Migratory Birds Considerations

The federal Endangered Species Act ("ESA"), and comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migrating birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. Moreover, as a result of a 2011 settlement agreement, the U.S. Fish and Wildlife Service ("FWS") was required to make a determination on listing numerous species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The FWS missed the deadline and continues to review species for listing under the ESA. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures, time delays or limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases. In addition, the federal government recently in the past has issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. In December 2017, the Department of Interior issued a new opinion revoking its prior enforcement policy and concluded that an incidental take is not a violation of the Migratory Bird Treaty Act. In August 2020, a federal district court struck down the December 2017 opinion, and the Department of the Interior responded by issuing a new rule in January 2021 that reduced the activities that could incur liability under the MBTA. The Biden administration has since revoked the January 2021 rule; published an Advanced Notice of Proposed Rulemaking announcing an intent to solicit comments to help develop proposed regulations establishing a permitting system to authorize, under certain circumstances, the incidental take of migratory birds; and issued a Director's Order "establishing criteria for the types of conduct that will be a priority for enforcement activities with respect to incidental take of migratory birds."

OSHA

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

Related Permits and Authorizations

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

Related Insurance

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

Human Capital Resources

As of December 31, 2021, we had 168 total employees, 148 of which were full-time employees. From time to time we utilize the services of independent contractors to perform various field and other services. We are not a party to any collective bargaining agreements, and have not experienced any strikes or work stoppages. In general, we believe that employee relations are satisfactory.

We are focused on attracting, engaging, developing, retaining and rewarding top talent. We strive to enhance the economic and social well-being of our employees and the communities in which we operate. We are committed to providing a welcoming, inclusive environment for our workforce, with best-in-class training and career development opportunities to enable employees to thrive and achieve their career goals. The health, safety, and well-being of our employees is of the utmost importance.

In response to COVID-19, we adopted enhanced safety measures and practices to protect employee health and safety and minimize the risk of business disruption.

Legal Proceedings

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

MANAGEMENT

Management of TXO Energy Partners

We are managed and operated by the Board and executive officers of our general partner. Our general partner is owned by the Founders. All of our independent directors will be appointed prior to the date our common units are listed for trading on the NYSE. Our unitholders will not be entitled to elect our general partner or its directors or otherwise directly participate in our management or operations. Our general partner owes certain contractual duties to our unitholders as well as a fiduciary duty to its owners.

Upon the closing of this offering, we expect that our general partner will have eight directors, each of whom will be appointed by the general partner. At least one of the directors will be independent as defined under the standards established by the NYSE and the Exchange Act. The NYSE does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the Board or to establish a compensation committee or a nominating committee. However, our general partner is required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act, subject to certain transitional relief during the one-year period following consummation of this offering. We will have at least one member of the audit committee appointed to the Board by the date our common units first trade on the NYSE.

Our operations will be conducted through, and our assets will be owned by, various subsidiaries. However, we will not have any employees. Our general partner has the sole responsibility for providing the personnel necessary to conduct our operations, whether through directly hiring personnel or by obtaining services of personnel employed by third parties, but we sometimes refer to these individuals, for drafting convenience only, in this prospectus as our employees because they provide services directly to us.

Following the consummation of this offering, neither our general partner nor the Founders will receive any management fee or other compensation in connection with our general partner's management of our business, but we will reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, benefits, bonus, long term incentives and other amounts paid to persons who perform services for us or on our behalf. Please read "Certain Relationships and Related Transactions."

In evaluating director candidates, our general partner will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the Board to fulfill their duties.

Executive Officers and Directors of Our General Partner

The following table sets forth certain information regarding the current executive officers and directors of our general partner upon consummation of this offering.

Name	Age	Position with TXO Energy GP, LLC
Bob R. Simpson	74	Chief Executive Officer, Chairman and Director
Brent W. Clum	59	President of Business Operations and Chief Financial Officer, Director
Keith A. Hutton	63	President of Production and Development, Director
Scott T. Agosta	57	Chief Accounting Officer
Vaughn O. Vennerberg II	68	Executive Vice President, Director
Phillip R. Kevil	71	Director
Rick J. Settle	32	Director
J. Luther King, Jr.	82	Director
William ("Bill") H. Adams III	64	Director

Bob R. Simpson—Chief Executive Officer. Bob R. Simpson founded MorningStar in June 2012 and has served as a Director and the Chairman of the Board of MorningStar since its founding and has served as our Chief Executive Officer effective July, 2022. Mr. Simpson previously served as the Chairman and a Director of Southland from February 2015 until January 2020. Since August 2010 and until September of 2020, Mr. Simpson served as Co-Chairman of the Rangers Baseball Express and since September of 2020, he has served as Chair of the Executive Committee. He also served as Chief Executive Officer of XTO (a company he founded) until 2008 and as Chairman of XTO until 2010 when XTO merged with Exxon for $41 billion in one of the largest transactions in history for an independent oil and gas company. Mr. Simpson attended Baylor University, where he earned a B.B.A. in Accounting magna cum laude and then an M.B.A. The University later designated him as the "Top Business Graduate of the 1970s." He served in the Texas Army National Guard after graduation and then earned his certified public accountant ("CPA") designation.

We believe that Mr. Simpson's industry experience and deep knowledge of our business make him well suited to serve as a member of our board of directors.

Brent W. Clum—President of Business Operations and Chief Financial Officer. Brent W. Clum has served as our Chief Financial Officer since the founding of MorningStar in June 2012, and President of Business Operations since July, 2022. He has also served as Chief Financial Officer of MorningStar since October 2012. Mr. Clum served as Chief Financial Officer and Director of Southland from February 2015 until January 2020. Since August 2010, he has served as Chairman of the Finance and Audit Committee of Rangers Baseball Express. He served as Senior Vice President and Treasurer of XTO until the Exxon acquisition. Additionally, Mr. Clum has served as a Board Member of the Junior Achievement of the Chisholm Trail since September 2005. Prior to joining XTO, Mr. Clum worked as a portfolio manager at Luther King Capital Management, served as a Managing Director at Invesco and was an Analyst for T. Rowe Price and Associates. He graduated from Baylor University with a Bachelors in Business Administration in Finance, Accounting and Marketing and from the Harvard Graduate School of Business with a Master's in Business Administration. He is a CPA and a chartered financial analyst ("CFA").

We believe that Mr. Clum's industry experience and deep knowledge of our business make him well suited to serve as a member of our board of directors.

Keith A. Hutton—President of Production and Development. Keith A. Hutton was named our President of Production and Development in July, 2022. He previously served as the Chief Executive Officer of MorningStar and has served as Director of MorningStar, in each case, since its founding in June 2012. Mr. Hutton served as Director of Southland from February 2015 until January 2020. Mr. Hutton also served as Chief Executive Officer and Director of XTO until the time of the Exxon acquisition. He remained a consultant with Exxon until January 2012. Keith held various management positions for XTO over his 25 year career and was promoted to CEO in December 2008. Prior to joining XTO Energy in 1987, Mr. Hutton was employed with Sun Oil Company in both the international and domestic divisions for five years. He graduated from Texas A&M University with a B.S. in Petroleum Engineering and was named a Harold Vance Department of Petroleum Engineering Distinguished Graduate in 2009.

We believe that Mr. Hutton's industry experience and deep knowledge of our business make him well suited to serve as a member of our board of directors.

Scott T. Agosta—Chief Accounting Officer. Scott T. Agosta was named our Chief Accounting Officer in July, 2022. He has served as Chief Accounting Officer and Controller of MorningStar since its founding in June 2012. He also served as Chief Accounting Officer and Controller of Southland from August 2017 until January 2020. He served as Vice President—Financial Reporting of XTO from February 2005 until the Exxon acquisition in March 2012. Additionally, Mr. Agosta has served as a Board Member of the Junior Achievement of the Chisholm Trail since August 2009. Prior to joining XTO, Mr. Agosta worked as the Manager—Financial Reporting and Analysis at Devon Energy Corporation, served as Manager—Financial Reporting at Albemarle Corporation and was an Audit Manager at KPMG. He graduated from Louisiana State University with a B.B.A in Accounting. He is a CPA.

Vaughn O. Vennerberg, II—Executive Vice President. Vaughn O. Vennerberg, II was named our Executive Vice President in July, 2022. He previously served as President of MorningStar since its founding in June, 2012. He served as President and Director of XTO until his retirement at the time of the Exxon acquisition. Prior to becoming President in 2008, he served in various leadership positions over his 25-year career with the company. Prior to joining XTO, Mr. Vennerberg was employed by Cotton Petroleum Corporation and Texaco Inc. Mr. Vennerberg holds a current appointment to the Washington D.C.-based National Petroleum Council and has served in various roles with state petroleum industry boards in Oklahoma, Texas, Wyoming, Alaska, and New Mexico. Mr. Vennerberg received a B.S. degree from Oklahoma State University in 1976 and an honorary Doctorate of Humane Letters in 2012. In 2016, he was inducted into the Oklahoma State University "Hall of Fame."

We believe that Mr. Vennerberg's industry experience and deep knowledge of our business make him well suited to serve as a member of our board of directors.

Phillip R. Kevil—Director. Phillip R. Kevil was named our Director in July, 2022. He served as Director and as a member of the Audit Committee for XTO from 2004 until 2010. In this position, Mr. Kevil reviewed all of XTO's SEC filings. He also served as Vice President – Tax at XTO from 1987 until 1997. Mr. Kevil was responsible for all tax functions for Southland from 1975 until 1986. He graduated from the University of Texas at Arlington with a B.A in Accounting.

We believe that Mr. Kevil's industry experience and deep knowledge of our business make him well suited to serve as a member of our board of directors.

Rick J. Settle—Director. Rick J. Settle was named our Director in July, 2022. Mr. Settle has served as Director of Kindthread since November 2021 and as Director of Aquila Environmental since November 2017. Additionally, Mr. Settle has served as Director of Heart of Texas Propane since September 2017 and served as Director of MorningStar since July 2020. Further, he has been a Principal of Luther King Management, Headwater Investments since October 2014. Mr. Settle worked as a financial analyst for Citigroup from June 2013 until October 2014. He graduated from the Texas Christian University with a B.B.A. in Finance, Entrepreneurial Management. He is a certified financial analyst.

We believe that Mr. Settle's industry experience and deep knowledge of our business make him well suited to serve as a member of our board of directors.

J. Luther King, Jr.—Director. J. Luther King, Jr. was named our Director in July, 2022. Mr. King has served as Director of the general partner of MorningStar since 2016. He served as Director of Tyler Technologies, Inc. from May 2004 until May 2021, serving on the Compensation and Audit Committees throughout his tenure at the company. Additionally, he has served as Director of LKCM Funds since February 1994. Mr. King also served as Director of Encore Energy Partners LP and as Director of XTO. Over the course of his career, he has served on the boards of several publicly traded companies, three of which were listed on the NYSE. In his position as a director of these companies, Mr. King has served as Chair of both Audit and Compensation committees. Mr. King currently serves as President of Luther King Capital Management, a position he has held since February 1979. He attended Texas Christian University, where he earned a B.S.C. and then an M.B.A. Mr. King is a CFA and was recognized by CFA Magazine as "Most Inspiring" in the Investment Advisory Profession in 2007. Additionally, Mr. King is a founding member of the Strategic Advisory Board of the CFA Society of Dallas/Fort Worth.

We believe that Mr. King's industry experience and deep knowledge of our business make him well suited to serve as a member of our board of directors.

William ("Bill") H. Adams III—Director. Bill H. Adams was named our Director in July, 2022. Mr. Adams currently serves as Director of Kimbell Royalty GP, LLC, a position he has held since January 2017. In this position, Mr. Adams has served on the Audit, Compensation and Conflicts committees of the company. Mr. Adams served as Director of Double B Holdings, LLC from 2012 until 2021. Additionally, Mr. Adams has served as Director of Graham Savings Bank since 2018, of JBN Investments, LLC since 2010, of Back Holdings, LLC since 2007 and of Jabb Associates, Inc. since 1997. Mr. Adams has also held the position of Chairman and has been a principal owner of Texas Appliance Supply, Inc., a wholesale and retail distribution company, since 2007. Prior to its sale to Exxon Mobil Corporation in 2010, he served on the board of directors of XTO Energy Inc., where he chaired the Compensation, Corporate Governance and Nominating committees. Previously, Mr. Adams had a 25-year career in commercial and energy banking, most recently as Executive Regional President of Texas Bank in Fort Worth, before retiring in 2006. He also served as President of Frost Bank-Arlington. Mr. Adams received a B.B.A. in Finance from Texas Tech University.

We believe that Mr. Adams' industry experience and deep knowledge of our business make him well suited to serve as a member of our board of directors.

Southland Bankruptcy

On January 27, 2020, Southland, filed a voluntary petition in the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court"). With the approval of the Bankruptcy Court, in May 2020 Southland sold its assets in the San Juan Basin to MorningStar Partners L.P. for $10.2 million. At the time of filing for bankruptcy and the Bankruptcy Court's approval of its plan of reorganization, Bob R. Simpson, Scott T. Agosta Keith A. Hutton, Vaughn O. Vennerberg II and Brent W. Clum were acting or former officers of Southland and were affiliates of the Company. As of January 2020, none of these individuals were employed by or affiliated with Southland.

Reimbursement of Expenses of Our General Partner

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us.

Board of Directors

Our board of directors currently consists of 10 members. Prior to the date that our common units are first traded on the NYSE, we expect to have a eight-member board of directors.

In evaluating director candidates, we will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the Board to fulfill their duties. We are in the process of identifying individuals who meet these standards and the relevant independence requirements.

Our directors hold office until the earlier of their death, resignation, retirement, disqualification or removal or until their successors have been duly elected and qualified.

Director Independence

Our independent directors will meet the independence standards established by the NYSE listing rules.

Committees of the Board of Directors

The Board will have an audit committee, a compensation committee, a conflicts committee, and such other committees as the Board shall determine from time to time. The NYSE listing rules do not require a listed limited partnership to establish a compensation committee or a nominating and corporate governance committee. However, we have established a compensation committee that will have the responsibilities set forth below.

Audit Committee

We are required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE listing rules and rules of the SEC. The audit committee will assist the Board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee will have the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee will also be responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to the audit committee and our management. Initially, will serve on the audit committee.

Conflicts Committee

In accordance with the terms of our partnership agreement, at least two members of the Board will serve on our conflicts committee to review specific matters that may involve conflicts of interest. The members of our conflicts committee cannot be officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors. In addition, the members of our conflicts committee cannot own any interest in our general partner or its affiliates or any interest in us or our subsidiaries other than common units or awards, if any, under our incentive compensation plan. In connection with   and   appointments to the board, we expect that   and   will serve as members of our conflicts committee. Please read "Conflicts of Interest and Duties."

Compensation Committee

Effective upon the consummation of this offering, the members of our compensation committee will be   , and   will serve as chair of the compensation committee. Each of the members of our compensation committee will be independent under the applicable rules and regulations of the NYSE, will be a "non-employee director" as defined in Rule 16b-3 promulgated under the Exchange Act and will be an "outside director" as that term is defined in Section 162(m) of the Code (Section 162(m)). The compensation committee will operate under a written charter that satisfies the applicable standards of the SEC and the NYSE.

The compensation committee's responsibilities include:

- annually reviewing and approving corporate goals and objectives relevant to compensation of our chief executive officer and our other executive officers;
- annually reviewing and making recommendations to our board of directors with respect to the compensation of our chief executive officer and determining the compensation for our other executive officers;
- reviewing and making recommendations to our board of directors with respect to director compensation; and
- overseeing and administering our equity incentive plans.

From time to time, our compensation committee may use outside compensation consultants to assist it in analyzing our compensation programs and in determining appropriate levels of compensation and benefits. The compensation committee will review and evaluate, at least annually, the performance of the compensation committee and its members, including compliance by the compensation committee with its charter.

Board Leadership Structure

Leadership of our general partner's board of directors is vested in a Chairman of the Board. Mr. Bob Simpson currently serves as a Director and the Chairman of the Board, and we have no policy with respect to the separation of the offices of chairman of the Board and chief executive officer. Instead, that relationship is defined and governed by the amended and restated limited liability company agreement of our general partner, which permits the same person to hold both offices. Directors of the Board are designated or elected by the Founders. Accordingly, unlike holders of common stock in a corporation, our unitholders will have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement.

Board Role in Risk Oversight

Our corporate governance guidelines will provide that the Board is responsible for reviewing the process for assessing the major risks facing us and the options for their mitigation. This responsibility will be largely satisfied by our audit committee, which is responsible for reviewing and discussing with management and our independent registered public accounting firm our major risk exposures and the policies management has implemented to monitor such exposures, including our financial risk exposures and risk management policies.

EXECUTIVE COMPENSATION AND OTHER INFORMATION

General

We do not directly employ any of the persons responsible for managing our business. Our general partner's executive officers will manage our business as part of the services provided by our general partner to us under the Partnership Agreement. Immediately prior to the closing of this offering, we and our general partner will enter into a services agreement with the Services Company, pursuant to which the Services Company will provide administrative and operating services to us for our field operations. Although all of the employees that conduct our business are either employed by our general partner or the Services Company, we sometimes refer to these individuals in this prospectus as our employees.

All of our general partner's executive officers and other employees necessary to operate our business will be employed and compensated by either our general partner or the Services Company, subject to reimbursement by our general partner. The compensation for all of our executive officers will be indirectly paid by us to the extent provided for in the partnership agreement because we will reimburse our general partner for compensation it pays related to management of our business. Please see "Certain Relationships and Related Party Transactions—Agreements with Affiliates in Connection with the Transactions—Services Agreement" and "—Reimbursement of Expenses of Our General Partner."

The Founders, as the only members of our general partner, will have responsibility and authority for compensation-related decisions for our Chief Executive Officer and, upon consultation and recommendations by our Chief Executive Officer, for our other executive officers. Equity grants pursuant to our long-term incentive plan will also be administered by the Founders. Our predecessor historically compensated certain of its executive officers primarily with base salary and cash bonuses.

In connection with this offering, the Founders may consider the compensation structures and levels that they believe will be necessary for executive recruitment and retention for us as a public company. The Founders expect to examine the compensation practices of our peer companies and may also review compensation data from the exploration and production industry generally.

Compensation of Directors

Officers or employees of our general partner or its affiliates, including the Services Company, who also serve as directors will not receive additional compensation for their service as a director of our general partner. The amount of compensation to be paid to our general partner's non-employee directors has not yet been determined.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our common units that, upon the consummation of this offering and the related transactions, will be owned by:

- beneficial owners of more than 5% of our common units;
- each named executive officer of our general partner; and
- all directors, director nominees and executive officers of our general partner as a group.

The table assumes the underwriters' option to purchase additional common units from us is not exercised. The percentage of units beneficially owned is based on common units being outstanding immediately following this offering.

	Common Units to be Beneficially Owned	Percentage of Common Units to be Beneficially Owned
Name of Beneficial Owner(1)		
5% Stockholders:		
Diamond S. Energy Company		
GEF-DTOE, Inc.		
GEF-PUE, LP		
PDLP MorningStar LLC		
Named Executive Officers, Directors and Director Nominees		
Bob R. Simpson(1)		
Brent W. Clum		
Keith A. Hutton		
Scott T. Agosta		
Vaughn O. Vennerberg II		
Phillip R. Kevil		
Rick J. Settle		
J. Luther King, Jr.		
Bill H. Adams III		
All executive officers, directors and director nominees as a group (8 persons)		

(1) Beneficial ownership is determined under the rules of the SEC and generally includes voting or investment power with respect to securities. Unless otherwise noted, the address for each beneficial owner listed below is 400 W 7th St., Fort Worth, TX 76102.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Upon the consummation of this offering, assuming the underwriters do not exercise their option to purchase additional common units, the Existing Owners will own common units representing an approximate % limited partner interest in us, and the Founders will own and control our general partner. The Founders will appoint all of the directors of our general partner, which will own a non-economic general partner interest in us. These percentages do not reflect any common units that may be issued under the long-term incentive plan that our general partner expects to adopt prior to the closing of this offering.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with our formation, ongoing operation and liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, were not the result of arm's length negotiations.

Formation Stage

The consideration received by our general partner in connection with the Reorganization Transactions	We will distribute approximately $ million in cash to our general partner.

Operational Stage

Distributions of available cash to affiliates of our general partner	We make cash distributions to our unitholders, including affiliates of our general partner, pro rata.
	Upon completion of this offering, the affiliates of our general partner will own common units, representing % of our outstanding common units and would receive a pro rata percentage of the cash distributions that we distribute in respect thereof.
Payments to our general partner and its affiliates	Our general partner will not receive a management fee or other compensation for its management of our partnership, but we will reimburse our general partner and its affiliates for costs and expenses they incur and payments they make on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us.

Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its non-economic general partner interest will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests. Please read "Our Partnership Agreement—Withdrawal or Removal of Our General Partner."
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Affiliates in Connection with the Reorganization Transactions

In connection with the closing of this offering, we, our general partner and its affiliates will enter into the various documents and agreements that will affect the transactions described in "Prospectus Summary—Reorganization Transactions and Partnership Structure." These agreements have been negotiated among affiliated parties and, consequently, are not the result of arm's length negotiations. All of the transaction expenses incurred in connection with these transactions, including the expenses associated with transferring assets to us, will be paid from the proceeds of this offering.

Contribution Agreement

In connection with the closing of this offering, our existing equity holders will contribute all of our outstanding equity interests in the company to a newly formed parent company, MorningStar Partners II, L.P., a Delaware limited partnership. All of the transaction expenses incurred in connection with these transactions will be paid from the proceeds of this offering.

Services Agreement

Contemporaneously with the closing of this offering, we expect to enter into a services agreement with a subsidiary of MorningStar Partners II, L.P. (the "Services Company") pursuant to which the Services Company will provide management, administrative and operating services to us. Under the services agreement, we will reimburse the Services Company, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf.

Other Transactions with Related Persons

We occupy a building owned by MorningStar Capital LLC, a limited liability company owned by Mr. Simpson, our Chief Executive Officer and the Chairman of the Board. In lieu of paying rent, we paid property taxes and paid for repairs and maintenance on behalf of MorningStar Capital LLC in the amount of $0.9 million in 2021 and $1.5 million in 2020.

Procedures for Review, Approval or Ratification of Transactions with Related Persons

We expect that the Board will adopt policies for the review, approval and ratification of transactions with related persons. We anticipate the Board will adopt a written code of business conduct and ethics, under which a director would be expected to bring to the attention of the chief executive officer or the Board any conflict or potential conflict of interest that may arise between the director in his or her personal capacity or any affiliate of the director in his or her personal capacity, on the one hand, and us or our general partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the Board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between our general partner or its affiliates, on the one hand, and us or our unitholders, on the other hand, the resolution of any such conflict or potential conflict should be addressed by the Board in accordance with the provisions of our partnership agreement. At the discretion of the Board in light of the circumstances, the resolution may be determined by the Board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under our partnership agreement.

Upon our adoption of our code of business conduct, we would expect that any executive officer will be required to avoid personal conflicts of interest unless approved by the Board.

Please read “Conflicts of Interest and Duties—Conflicts of Interest” for additional information regarding the relevant provisions of our partnership agreement.

The code of business conduct and ethics described above will be adopted in connection with the closing of this offering, and as a result, the transactions described above were not reviewed according to such procedures.

CONFLICTS OF INTEREST AND DUTIES

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including the Founders) on the one hand, and us and our limited partners, on the other hand. The directors and officers of our general partner have fiduciary duties to manage our general partner in a manner that is not adverse to the best interests of its owners. At the same time, our general partner has a duty to manage us in a manner that is not adverse to the best interests of our partnership. The Delaware Revised Uniform Limited Partnership Act(the “Delaware Act”), provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties otherwise owed by a general partner to limited partners and the partnership. Pursuant to these provisions, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of our general partner and the methods of resolving conflicts of interest. Our partnership agreement also specifically defines the remedies available to limited partners for actions taken that, without these defined liability standards, might constitute breaches of fiduciary duty under applicable Delaware law.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us or any other partner, on the other hand, our general partner will resolve that conflict. Our general partner may seek the approval of such resolution from the conflicts committee of the Board or from our unitholders. There is no requirement under our partnership agreement that our general partner seek the approval of the conflicts committee or our unitholders for the resolution of any conflict, and, under our partnership agreement, our general partner may decide to seek such approval or resolve a conflict of interest in any other way permitted by our partnership agreement, as described below, in its sole discretion. Our general partner will decide whether to refer the matter to the conflicts committee or our unitholders on a case-by-case basis. An independent third party is not required to evaluate the fairness of the resolution. In determining whether to refer a matter to the conflicts committee or to our unitholders for approval, our general partner will consider a variety of factors, including the nature of the conflict, the size and dollar amount involved, the identity of the parties involved and any other factors the Board deems relevant in determining whether it will seek approval from the conflicts committee or our unitholders. Whenever our general partner makes a determination to refer or not to refer any potential conflict of interest to the conflicts committee for approval or to seek or not to seek unitholder approval, our general partner is acting in its individual capacity, which means that it may act free of any duty or obligation whatsoever to us or our unitholders and will not be required to act in good faith or pursuant to any other standard or duty imposed by our partnership agreement or under applicable law, other than the implied contractual covenant of good faith and fair dealing. For a more detailed discussion of the duties applicable to our general partner, as well as the implied contractual covenant of good faith and fair dealing, please read “—Duties of Our General Partner.”

Our general partner will not be in breach of its obligations under our partnership agreement or its duties to us or our limited partners if the resolution of the conflict is:

- approved by the conflicts committee, which our partnership agreement defines as “special approval”;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;

- determined by the Board to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- determined by the Board to be fair and reasonable to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If our general partner seeks approval from the conflicts committee, then it will be presumed that, in making its decision, the conflicts committee acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. If our general partner does not seek approval from the conflicts committee or our unitholders and our general partner's board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee of our general partner's board of directors may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement requires someone to act in good faith, it requires that person to subjectively believe that he or she is acting in a manner that is not adverse to the best interests of the partnership or that the determination to take or not to take action meets the specified standard, for example, a transaction on terms no less favorable to the us than those generally being provided to or available from unrelated third parties, or is "fair and reasonable" to us. In taking such action, such person may take into account the totality of the circumstances or the totality of the relationships between the parties involved, including other relationships or transactions that may be particularly favorable or advantageous to us. If that person has the required subjective belief, then the decision or action will be conclusively deemed to be in good faith for all purposes under our partnership agreement. Please read "Management—Committees of the Board of Directors—Conflicts Committee" for information about the conflicts committee of our general partner's board of directors.

Conflicts of interest could arise in the situations described below, among others:

Agreements between us, on the one hand, and our general partner and its affiliates, on the other hand, are not and will not be the result of arm's-length negotiations.

Neither our partnership agreement nor any of the other agreements, contracts and arrangements between us and our general partner and its affiliates are or will be the result of arm's-length negotiations. Our partnership agreement generally provides that any affiliated transaction, such as an agreement, contract or arrangement between us and our general partner and its affiliates that does not receive unitholder or conflicts committee approval, must be determined by the Board to be:

- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- "fair and reasonable" to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner's affiliates may compete with us and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than those incidental to its ownership of interests in us. However, affiliates of our general partner are not prohibited from engaging in other businesses or activities, including those that might directly compete with us. In addition, under our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to our general partner and its affiliates. As a result, neither our general partner nor any of its affiliates have any obligation to present business opportunities to us.

Our general partner is allowed to take into account the interests of parties other than us in resolving conflicts of interest.

Our partnership agreement contains provisions that permissibly modify and reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner or otherwise, free of any duty or obligation whatsoever to us and our unitholders, including any duty to act in a manner not adverse to the best interests of us or our unitholders, other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in our partnership agreement does not provide for a clear course of action. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples of decisions that our general partner may make in its individual capacity include the allocation of corporate opportunities among us and our affiliates, the exercise of its limited call right or its voting rights with respect to the units it owns, whether to exercise its registration rights, and whether or not to consent to any merger, consolidation or conversion of the partnership or amendment to our partnership agreement.

We do not have any officers or employees and rely solely on officers and employees of our general partner and its affiliates.

Affiliates of our general partner conduct businesses and activities of their own in which we have no economic interest. There could be material competition for the time and effort of the officers and employees who provide services to our general partner.

Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties and limits our general partner's liabilities and the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty under applicable Delaware law.

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;

- provides that our general partner shall not have any liability to us or our limited partners for decisions made in its capacity so long as such decisions are made in good faith;

- generally provides that in a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our public common unitholders or the conflicts committee and the Board determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest is either on terms no less favorable to us than those generally being provided to or available from unrelated third parties or is “fair and reasonable” to us, considering the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us, then it will be presumed that in making its decision, the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us challenging such decision, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers or directors, as the cases may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful.

By purchasing a common unit, a common unitholder will be deemed to have agreed to become bound by the provisions in our partnership agreement, including the provisions discussed above.

Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval, on such terms as it determines to be necessary or appropriate to conduct our business including, but not limited to, the following:

- the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of, or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible into or exchangeable for equity interests of the partnership, and the incurring of any other obligations;

- the making of tax, regulatory and other filings, or rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets;

- the acquisition, disposition, mortgage, pledge, encumbrance, hypothecation or exchange of any or all of our assets or the merger or other combination of us with or into another person;

- the negotiation, execution and performance of any contracts, conveyances or other instruments;

- the distribution of cash held by the partnership;

- the selection and dismissal of employees and agents, outside attorneys, accountants, consultants and contractors and the determination of their compensation and other terms of employment or hiring;

- the maintenance of insurance for our benefit and the benefit of our partners and indemnitees;

- the formation of, or acquisition of an interest in, and the contribution of property and the making of loans to, any further limited or general partnerships, joint ventures, corporations, limited liability companies or other entities;
- the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity and otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense and the settlement of claims and litigation;
- the indemnification of any person against liabilities and contingencies to the extent permitted by law;
- the purchase, sale or other acquisition or disposition of our equity interests, or the issuance of additional options, rights, warrants and appreciation rights relating to our equity interests; and
- the entering into of agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner.

Please read "The Partnership Agreement" for information regarding the voting rights of unitholders.

We will reimburse our general partner and its affiliates for expenses.

Pursuant to our partnership agreement, we will reimburse our general partner and its affiliates for costs and expenses they incur and payments they make on our behalf. Our partnership agreement provides that our general partner will determine such other expenses that are allocable to us, and our partnership agreement does not limit the amount of expenses for which our general partner and its affiliates may be reimbursed. Such reimbursements will be made prior to making any distributions on our common units. Please read "The Partnership Agreement—Reimbursement of Expenses."

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party to such agreements has recourse only against our assets and not against our general partner or its assets or any affiliate of our general partner or its assets. Our partnership agreement permits our general partner to limit its or our liability, even if we could have obtained terms that are more favorable without the limitation on liability.

Common units are subject to our general partner's limited call right.

Our general partner may exercise its right to call and purchase common units as provided in our partnership agreement or assign this right to one of its affiliates or to us free of any liability or obligation to us or our partners. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please read "The Partnership Agreement—Limited Call Right."

Limited partners have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us, on the one hand, and our general partner and its affiliates, on the other, will not grant to the limited partners, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

The attorneys, independent accountants and others who perform services for us have been retained by our general partner. Attorneys, independent accountants and others who perform services for us are selected by our general partner or the conflicts committee and may also perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases.

Duties of our General Partner

The Delaware Act provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties otherwise owed by a general partner to limited partners and the partnership, provided that partnership agreements may not eliminate the implied contractual covenant of good faith and fair dealing. This implied covenant is a judicial doctrine utilized by Delaware courts in connection with interpreting ambiguities in partnership agreements and other contracts and does not form the basis of any separate or independent fiduciary duty in addition to the express contractual duties set forth in our partnership agreement. Under the implied contractual covenant of good faith and fair dealing, a court will enforce the reasonable expectations of the partners where the language in our partnership agreement does not provide for a clear course of action.

As permitted by the Delaware Act, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of our general partner and the methods of resolving conflicts of interest. We have adopted these provisions to allow our general partner or its affiliates to engage in transactions with us that otherwise might be prohibited or restricted by state-law fiduciary standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. We believe this is appropriate and necessary because the Board has fiduciary duties to manage our general partner in a manner that is not adverse to the best interests of its owner, the Founders, as well as to the best interests of our partnership. Without these provisions, our general partner's ability to make decisions involving conflicts of interest would be restricted. These provisions enable our general partner to take into consideration the interests of all parties involved in the proposed action. These provisions also strengthen the ability of our general partner to attract and retain experienced and capable directors. These provisions disadvantage the limited partners because they restrict the remedies available to limited partners for actions that, without those provisions, might constitute breaches of fiduciary duty, as described below and permit our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interest. The following is a summary of:

- the fiduciary duties imposed on general partners of a limited partnership by the Delaware Act in the absence of partnership agreement provisions to the contrary;
- the contractual duties of our general partner contained in our partnership agreement that replace the fiduciary duties referenced in the preceding bullet that would otherwise be imposed by Delaware law on our general partner; and
- certain rights and remedies of our limited partners contained in our partnership agreement and the Delaware Act.

Delaware law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner of a Delaware limited partnership to use that amount of care that an ordinarily careful and prudent person would use in similar circumstances and to consider all material information reasonably available in making business decisions. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present unless such transaction were entirely fair to the partnership. Our partnership agreement modifies these standards as described below.
Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues as to compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in "good faith," meaning that it subjectively believed that the decision was not adverse to our best interests, and our general partner will not be subject to any other standard under our partnership agreement or applicable law, other than the implied contractual covenant of good faith and fair dealing. If our general partner has the required subjective belief, then the decision or action will be conclusively deemed to be in good faith for all purposes under our partnership agreement. In taking such action, our general partner may take into account the totality of the circumstances or the totality of the relationships between the parties involved, including other relationships or transactions that may be particularly favorable or advantageous to us. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act free of any duty or obligation whatsoever to us or our limited partners, other than the implied contractual covenant of good faith and fair dealing. These standards reduce the obligations to which our general partner would otherwise be held under applicable Delaware law.
	Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not

approved by the public common unitholders or the conflicts committee of the Board must be determined by the Board to be:

- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- "fair and reasonable" to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If our general partner seeks approval from the conflicts committee, then it will be presumed that, in making its decision, the conflicts committee acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. If our general partner does not seek approval from the public common unitholders or the conflicts committee and the Board determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the bullet points above, then it will be presumed that, in making its decision, the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. These standards reduce the obligations to which our general partner would otherwise be held.

In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner, its affiliates and their officers and directors will not be liable for monetary damages to us or, our limited partners for losses sustained or liabilities incurred as a result of any acts or omissions unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that such person acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful.

Rights and remedies of limited partners	The Delaware Act favors the principles of freedom of contract and enforceability of partnership agreements and allows our partnership agreement to contain terms governing the rights of our unitholders. The rights of our unitholders, including voting and approval rights and the ability of the

partnership to issue additional units, are governed by the terms of our partnership agreement. Please read “The Partnership Agreement.” As to remedies of unitholders, the Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has wrongfully refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. These actions include actions against a general partner for breach of its fiduciary duties, if any, or of our partnership agreement. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.

By purchasing our common units, each common unitholder will be deemed to have agreed to be bound by the provisions in our partnership agreement, including the provisions discussed above. Please read “Description of the Common Units—Transfer of Common Units.” This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner to sign our partnership agreement does not render our partnership agreement unenforceable against that person.

Under our partnership agreement, we must indemnify our general partner and its officers, directors and managers, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that our general partner or these persons acted in bad faith or engaged in fraud or willful misconduct. We also must provide this indemnification for criminal proceedings unless our general partner or these other persons acted with knowledge that their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent that these provisions purport to include indemnification for liabilities arising under the U.S. federal securities laws, in the opinion of the SEC such indemnification is contrary to public policy and therefore unenforceable. Please read “The Partnership Agreement—Indemnification.”

DESCRIPTION OF THE COMMON UNITS

The Units

The common units represent limited partner interests in us. The holders of common units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of holders of common units in and to partnership distributions, please read this section and “Our Cash Distribution Policy and Restrictions on Distributions.” For a description of other rights and privileges of limited partners under our partnership agreement, including voting rights, please read “The Partnership Agreement.”

Transfer Agent and Registrar

Duties

We will retain a third party entity to serve as registrar and transfer agent for the common units. We expect to pay all fees charged by the transfer agent for transfers of common units, except the following, which must be paid by our unitholders:

- surety bond premiums to replace lost or stolen certificates or to cover taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There will be no charge to our unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their respective stockholders, directors, officers and employees against all claims and losses that may arise out of their actions for their activities in that capacity, except for any liability due to any gross negligence or willful misconduct of the indemnitee.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor is appointed, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of our partnership agreement; and

- gives the consents, waivers and approvals contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and this offering.

Our general partner may request that a transferee of common units certify that such transferee is an Eligible Holder. As of the date of this prospectus, an Eligible Holder means any person or entity qualified to hold an interest in oil and natural gas leases on federal lands that is:

- a citizen of the United States;

- a corporation organized under the laws of the United States or of any state thereof;

- a public body, including a municipality; or

- an association of United States citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof.

For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof.

In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in our partnership for the transferred common units. Our general partner will cause any transfers to be recorded on our books and records from time to time (or shall cause the transfer agent to do so, as applicable).

The transferor of common units will have a duty to provide the transferee with all information that may be necessary to transfer the common units. The transferor will not have a duty to insure the execution of the transfer application and certification by the transferee and will have no liability or responsibility if the transferee neglects or chooses not to execute and forward the transfer application and certification to the transfer agent.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder’s rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and any transfers are subject to the laws governing transfers of securities.

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. The form of our partnership agreement is included in this prospectus as Appendix A. We will provide prospective investors with a copy of our partnership agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please read “Our Cash Distribution Policy and Restrictions on Distributions” and “Provisions of Our Partnership Agreement Relating to Cash Distributions;”
- with regard to the duties of our general partner, please read “Conflicts of Interest and Duties;”
- with regard to the transfer of common units, please read “Description of the Common Units—Transfer Agent and Registrar—Transfer of Common Units;” and
- with regard to allocations of taxable income, taxable loss and other matters, please read “Material U.S. Federal Income Tax Consequences.”

Organization and Duration

Our partnership was organized in Delaware and will have a perpetual existence unless terminated pursuant to the terms of our partnership agreement.

Purpose

Our purpose under our partnership agreement is to engage in any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law. However, our general partner may not cause us to engage in any business activity that it determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes, except as otherwise provided below under “—Election to be Treated as a Corporation.”

Although our general partner has the ability to cause us and our subsidiary to engage in activities other than the ownership, acquisition, exploitation and development of oil and natural gas properties and the ownership, acquisition and operation of related assets, our general partner has no current plans to do so and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interests of us or our limited partners. Our general partner is generally authorized to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described under “—Limited Liability.”

Limited Voting Rights

The following is a summary of the unitholder vote required for each of the matters specified below. Matters that call for the approval of a “unit majority” require the approval of a majority of the common units.

Various matters require the approval of a "unit majority," which means:

- the approval of a majority of the outstanding common units.

At the closing of this offering, the Founders will have the ability to ensure passage of, as well as the ability to ensure the defeat of, any amendment which requires a unit majority by virtue of their % ownership of our common units. Our general partner and its affiliates (including the Founders) do not have the ability to ensure passage of, but do have the ability to ensure defeat of, any amendment that requires a unit majority.

In voting their common units, our general partner and its affiliates (including the Founders) will have no duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or our limited partners. The holders of a majority of the common units (including common units deemed owned by our general partner) represented in person or by proxy shall constitute a quorum at a meeting of such common unitholders, unless any such action requires approval by holders of a greater percentage of such units in which case the quorum shall be such greater percentage.

Issuance of additional units	No approval right. Please read "—Issuance of Additional Partnership Interests."
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please read "—Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority, in certain circumstances. Please read "—Merger, Consolidation, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please read "—Dissolution."
Continuation of our business upon dissolution	Unit majority. Please read "—Dissolution."
Withdrawal of our general partner	Under most circumstances, the approval of a majority of the outstanding common units, excluding common units held by our general partner and its affiliates (including the Founders), is required for the withdrawal of our general partner in a manner that would cause a dissolution of our partnership. Please read "—Withdrawal or Removal of Our General Partner."
Removal of our general partner	Not less than 66⅔% of the outstanding common units, including units held by our general partner and its affiliates (including the Founders), voting as a single class. Please read "—Withdrawal or Removal of Our General Partner."

Transfer of our general partner interest	Our general partner may transfer any or all of its general partner interest in us without a vote of our unitholders. Please read "—Transfer of General Partner Units."
Transfer of ownership interests in our general partner	No unitholder approval required. Please read "—Transfer of Ownership Interests in Our General Partner."
Election to be treated as a corporation	No approval right. Please read "—Election to be Treated as a Corporation."

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;
- asserting a claim arising pursuant to any provision of the Delaware Act; or
- asserting a claim governed by the internal affairs doctrine,

shall be exclusively brought in the Court of Chancery of the State of Delaware, regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware in connection with any such claims, suits, actions or proceedings.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he otherwise acts in conformity with the provisions of our partnership agreement, his liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. If it were determined, however, that the right or exercise of the right by our limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to the partnership agreement; or

- to take other action under the partnership agreement;

constituted "participation in the control" of our business for the purposes of the Delaware Act, then our limited partners could be held personally liable for our obligations under Delaware law, to the same extent as our general partner. This liability would extend to persons who transact business with us and reasonably believe that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, a substituted limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except that such person is not obligated for liabilities unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

Our operating subsidiary conducts business in New Mexico, Colorado and Texas, and we may have operating subsidiaries that conduct business in other states in the future. Maintenance of our limited liability as an owner of our operating subsidiary may require compliance with legal requirements in the jurisdictions in which our operating subsidiary conducts business, including qualifying our operating subsidiary to do business there.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership in our subsidiary or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by our limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then our limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of our limited partners.

Issuance of Additional Partnership Interests

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of our unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units or other partnership interests. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiary of equity interests, which may effectively rank senior to our common units.

Our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units or other partnership interests whenever, and on the same terms that, we issue those interests to persons other than our general partner and its affiliates, to the extent necessary to maintain the aggregate percentage interest in us of our general partner and its affiliates, including such interest represented by common units, that existed immediately prior to each issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership interests.

Amendment of the Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interests of us or our limited partners. To adopt a proposed amendment, other than the amendments discussed below under "—No Unitholder Approval," our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of our limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or

- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld in its sole discretion.

The provision of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by our general partner and its affiliates (including the Founders)). Upon the consummation of this offering, affiliates of our general partner (including the Founders) will own an aggregate of approximately % of our outstanding common units, representing an aggregate of approximately % of our outstanding limited partnership units.

No Limited Partner Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate for us to qualify or to continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state or to ensure that neither we, nor our subsidiary will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes, except as otherwise provided below under "—Election to be Treated as a Corporation";
- a change in our fiscal year or taxable year and related changes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or the directors, officers, agents or trustees of our general partner from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940, or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;
- an amendment that our general partner determines to be necessary or appropriate for the authorization or issuance of additional partnership securities or rights to acquire partnership securities;
- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership, limited liability company, joint venture or other entity, as otherwise permitted by our partnership agreement;
- any amendment necessary to require our limited partners to provide a statement, certification or other evidence to us regarding whether such limited partner is subject to United States federal income taxation on the income generated by us and to provide for the ability of our general partner to redeem the units of any limited partner who fails to provide such statement, certification or other evidence;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or

- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect our limited partners (or any particular class of limited partners) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of our units or to comply with any rule, regulation, guideline or requirement of any securities exchange on which our units are or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval

For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain an opinion of counsel that an amendment will not affect the limited liability of any limited partner under Delaware law. No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding common units unless we first obtain such an opinion.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected, but no vote will be required by any class or classes or type or types of limited partners that our general partner determines are not adversely affected in any material respect. Any amendment that reduces the voting percentage required to take any action other than to remove the general partner or call a meeting of unitholders is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced. Any amendment that would increase the percentage of units required to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be increased.

Merger, Consolidation, Sale or Other Disposition of Assets

A merger or consolidation of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger or consolidation and may decline to do so free of any fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interest of us or our limited partners.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us, among other things, to sell, exchange or otherwise dispose of all or substantially all of our and our subsidiary's assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination or sale of ownership interests of our subsidiary. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger or consolidation without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction will not result in a material amendment to our partnership agreement (other than an amendment that the general partner could adopt without the consent of other partners), each of our units will be an identical unit of our partnership following the transaction, and the partnership interests to be issued do not exceed 20% of our outstanding partnership interests immediately prior to the transaction.

If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or our subsidiary into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity, if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters, and the governing instruments of the new entity provide our limited partners and our general partner with the same rights and obligations as contained in our partnership agreement. The unitholders are not entitled to dissenters' rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until dissolved and terminated under our partnership agreement. We will dissolve upon:

- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner, other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or a withdrawal or removal followed by approval and admission of a successor;
- the election of our general partner to dissolve us, if approved by the holders of a unit majority;
- the entry of a decree of judicial dissolution of our partnership pursuant to the provisions of the Delaware Act; or
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law.

Upon a dissolution under the first bullet above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability under Delaware law of any limited partner; and

- neither our partnership nor our subsidiary would be treated as an association taxable as a corporation or otherwise be taxable as an entity for U.S. federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless our business is continued, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as described in "Provisions of Our Partnership Agreement Relating to Cash Distributions—Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to , 2032 without obtaining the approval of the holders of at least a majority of our outstanding common units, excluding common units held by our general partner and its affiliates (including the Founders), and furnishing an opinion of counsel regarding limited liability and tax matters. On or after , 2032, our general partner may withdraw as our general partner without first obtaining approval of any unitholder by giving at least 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw as our general partner without unitholder approval upon 90 days' notice to our limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than our general partner and its affiliates (including the Founders). In addition, our partnership agreement permits our general partner in some instances to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please read "—Transfer of General Partner Units."

Upon voluntary withdrawal of our general partner by giving notice to the other partners, the holders of a unit majority may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree to continue our business by appointing a successor general partner. Please read "—Termination and Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66⅔% of our outstanding units, voting together as a single class, including units held by our general partner and its affiliates (including the Founders), and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of our outstanding common units. The ownership of more than 33⅓% of our outstanding units by our general partner and its affiliates (including the Founders) would give them the practical ability to prevent our general partner's removal. Upon the consummation of this offering, affiliates of our general partner (including the Founders) will own an aggregate of approximately % of our outstanding common units, representing approximately % of our outstanding limited partnership units.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist our general partner will have the right to convert its general partner interest into common units or to receive cash in exchange for those interests based on the fair market value of the interests at the time.

In the event of removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the departing general partner's general partner interest for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and its affiliate and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and its affiliate and the successor general partner will determine the fair market value. If the departing general partner and its affiliate and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interest

Our general partner may transfer all or any of its general partner interest to an affiliate or a third party without the approval of our unitholders. As a condition of this transfer, the transferee must, among other things, assume the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

Our general partner and its affiliates (including the Founders) may at any time transfer common units to one or more persons without unitholder approval.

Transfer of Ownership Interests in Our General Partner

At any time, the members of our general partner may sell or transfer all or part of their membership interests in our general partner to an affiliate or a third party without the approval of our unitholders.

Election to be Treated as a Corporation

If at any time our general partner determines that (i) we should no longer be characterized as a partnership but instead as an entity taxed as a corporation for U.S. federal income tax purposes or (ii) common units held by unitholders other than our general partner and its affiliates should be converted into or exchanged for interests in a newly formed entity taxed as a corporation for U.S. federal income tax purposes whose sole asset is interests in us ("parent corporation"), then our general partner may, without unitholder approval, reorganize and cause us to be treated as an entity taxable as a corporation for U.S. federal income tax purposes or cause common units held by unitholders other than the general partner and its affiliates to be converted into or exchanged for interests in the parent corporation. In addition, if our general partner causes partnership interests in us to be held by a parent corporation, our Existing Owners may choose to retain their partnership interests in us rather than convert or exchange their partnership interests into parent corporation shares. The general partner may take any of the foregoing actions if it in good faith determines (meaning it subjectively believes) that such action is not adverse to our best interests. In making such determination, however, our general partner is not required to take into account the immediate and long-term tax consequences to our limited partners. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. The tax liability, if any, of a unitholder as a result of such an event may vary depending on the unitholder's particular situation and may vary from the tax liability of our general partner and each of our Existing Owners. Our general partner will have no duty or obligation to make any such determination or take any such actions, however, and may decline to do so free of any duty or obligation whatsoever to us or our limited partners, including any duty to act in a manner not adverse to the best interests of us or our limited partners.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our general partner or otherwise change the management of our general partner. If any person or group other than our general partner and its affiliates (including the Founders) acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the prior approval of the Board.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal, our general partner will have the right to convert its general partner interest into common units or receive cash in exchange for those interests based on the fair market value of those interests as of the effective date of its removal.

Limited Call Right

If at any time our general partner and its affiliates (including the Founders) own more than 80% of our then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days' notice. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by either of our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and

- the current market price calculated in accordance with our partnership agreement as of the date three business days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have its limited partner interests purchased at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The federal income tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of its common units in the market. Please read "Material U.S. Federal Income Tax Consequences—Disposition of Units."

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of common units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read "—Issuance of Additional Partnership Interests." However, if at any time any person or group, other than our general partner and its affiliates (including the Founders) or a direct or subsequently approved transferee of our general partner or its affiliates and specifically approved by our general partner, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent or an exchange agent.

Status as Limited Partner

By transfer of any common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Except as described under "—Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Non-Citizen Unitholders; Redemption

We may acquire interests in oil and natural gas leases on United States federal lands in the future. To comply with certain U.S. laws relating to the ownership of interests in oil and natural gas leases on federal lands, our general partner, acting on our behalf, may request any unitholder to furnish to the general partner within 30 days of the request a properly completed certificate certifying as to the unitholder's nationality, citizenship or other related status. If, following a request by our general partner, a unitholder fails to furnish such certification within the 30-day period or if the general partner determines that the unitholder's nationality, citizenship or other related status would create a substantial risk of cancellation or forfeiture of property in which the we have an interest, we will have the right to redeem the units held by such unitholder. Further, the units held by such unitholder will not be entitled to any voting rights and may not receive distributions in-kind upon our liquidation.

Furthermore, we have the right to redeem all of the common units of any holder that our general partner concludes is an Ineligible Holder or fails to furnish the information requested by our general partner. The redemption price in the event of such redemption for each unit held by such unitholder will be the current market price of such unit (the date of determination of which shall be the date fixed for redemption). The redemption price will be paid, as determined by our general partner, in cash or by delivery of a promissory note. Any such promissory note will bear interest at the rate of 5% annually and be payable in three equal annual installments of principal and accrued interest, commencing one year after the redemption date.

For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of our general partner or any departing general partner;
- any person who is or was a director, officer, manager, managing member, partner, fiduciary or trustee of any entity set forth in the preceding three bullet points;
- any person who is or was serving as a director, officer, manager, managing member, partner, fiduciary or trustee of another person at the request of our general partner or any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our general partner will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance covering liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. These expenses include salary, bonus, incentive compensation, and other amounts paid to persons who perform services for us or on our behalf, and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine in good faith the expenses that are allocable to us. The expenses for which we are required to reimburse our general partner are not subject to any caps or other limits.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For financial reporting and tax purposes, our fiscal year is the calendar year.

We will mail or make available to record holders of common units, within 105 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent registered public accounting firm. Except for our fourth quarter, we will also mail or make available summary financial information within 50 days after the close of each quarter. We will be deemed to have made any such report available if we file such report with the SEC on EDGAR or make the report available on a publicly available website which we maintain.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to our unitholders will depend on the cooperation of our unitholders in supplying us with specific information. Every unitholder will receive information to assist it in determining its federal and state tax liability and filing its federal and state income tax returns, regardless of whether such unitholder supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, obtain:

- a current list of the name and last known address of each record holder;
- copies of our partnership agreement and our certificate of limited partnership and related amendments thereto; and
- certain information regarding the status of our business and financial condition.

Our general partner may, and intends to, keep confidential from the limited partners, trade secrets or other information the disclosure of which our general partner determines is not in our best interests or that we are required by law or by agreements with third parties to keep confidential. Our partnership agreement limits the right to information that a limited partner would otherwise have under Delaware law.

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Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units or other partnership interests proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. Please read "Units Eligible for Future Sale."

UNITS ELIGIBLE FOR FUTURE SALE

After the sale of the common units offered hereby, the Existing Owners will hold an aggregate of common units. The sale of these units could have an adverse impact on the price of the common units or on any trading market that may develop.

The common units sold in this offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units owned by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1.0% of the total number of the securities outstanding; or
- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about us. A unitholder who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned his common units for at least six months (provided we are in compliance with the current public information requirement) or one year (regardless of whether we are in compliance with the current public information requirement), would be entitled to sell those common units under Rule 144 without regard to the volume limitations, manner of sale provisions and notice requirements of Rule 144.

Our Partnership Agreement and Registration Rights

Our partnership agreement provides that we may issue an unlimited number of limited partner interests of any type without a vote of the unitholders. Any issuance of additional common units or other equity interests would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, our common units then outstanding. Please read "The Partnership Agreement—Issuance of Additional Partnership Interests."

Under our partnership agreement, our general partner and its affiliates, including the Existing Owners, have the right to cause us to register under the Securities Act and applicable state securities laws the offer and sale of any common units or other partnership interests that they hold, which we refer to as registerable securities. Subject to the terms and conditions of our partnership agreement, these registration rights allow our general partner and its affiliates or their assignees holding any registerable securities to require registration of such registerable securities and to include any such registerable securities in a registration by us of common units or other partnership interests, including common units or other partnership interests offered by us or by any unitholder. Our general partner and its affiliates will continue to have these registration rights for two years following the withdrawal or removal of our general partner. In connection with any registration of units held by our general partner or its affiliates, we will indemnify each unitholder participating in the registration and its officers, directors, and controlling persons from and against any liabilities under the Securities Act or any applicable state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discounts. Except as described below, our general partner and its affiliates may sell their common units or other partnership interests in private transactions at any time, subject to compliance with applicable laws.

Lock-Up Agreements

The directors and executive officers of our general partner, and their respective affiliates, have agreed, subject to certain exceptions, not to sell any common units for a period of 180 days from the date of this prospectus. For a description of these lock-up provisions, please read "Underwriting."

Registration Statement on Form S-8

Prior to the completion of this offering, we expect to adopt a new long-term incentive plan (the "Long-Term Incentive Plan"). If adopted, we intend to file a registration statement on Form S-8 under the Securities Act to register common units issuable under the Long-Term Incentive Plan. This registration statement on Form S-8 is expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Accordingly, common units issued under the Long-Term Incentive Plan will be eligible for resale in the public market without restriction after the effective date of the Form S-8 registration statement, subject to applicable vesting requirements, Rule 144 limitations applicable to affiliates and the lock-up restrictions described above.

MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES

This section is a summary of the material U.S. federal income tax consequences that may be relevant to prospective common unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, is the opinion of Latham & Watkins LLP, counsel to our general partner and us, insofar as it relates to legal conclusions with respect to matters of U.S. federal income tax law. This section is based upon current provisions of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"), existing and proposed Treasury regulations promulgated under the Internal Revenue Code (the "Treasury Regulations") and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to "us" or "we" are references to TXO Energy Partners, and our operating subsidiaries.

The following discussion does not comment on all federal income tax matters affecting us or our unitholders and does not describe the application of the alternative minimum tax that may be applicable to certain unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, entities treated as partnerships for U.S. federal income tax purposes, trusts, nonresident aliens, U.S. expatriates and former citizens or long-term residents of the United States or other unitholders subject to specialized tax treatment, such as banks, insurance companies and other financial institutions, tax-exempt institutions, foreign persons (including, without limitation, controlled foreign corporations, passive foreign investment companies and foreign persons eligible for the benefits of an applicable income tax treaty with the United States), individual retirement accounts (IRAs), real estate investment trusts (REITs) or mutual funds, dealers in securities or currencies, traders in securities, U.S. persons whose "functional currency" is not the U.S. dollar, persons holding their units as part of a "straddle," "hedge," "conversion transaction" or other risk reduction transaction, persons subject to special tax accounting rules as a result of any item of gross income with respect to our common units being taken into account in an applicable financial statement and persons deemed to sell their units under the constructive sale provisions of the Internal Revenue Code. In addition, the discussion only comments, to a limited extent, on state, local and foreign tax consequences. Accordingly, we encourage each prospective common unitholder to consult his own tax advisor in analyzing the state, local and foreign tax consequences particular to him of the ownership or disposition of common units and potential changes in applicable laws, including the impact of U.S. tax reform legislation.

No ruling has been requested from the IRS regarding our characterization as a partnership for tax purposes. Instead, we will rely on opinions of Latham & Watkins LLP. Unlike a ruling, an opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for our common units, including the prices at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

All statements as to matters of U.S. federal income tax law and legal conclusions with respect thereto, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Latham & Watkins LLP and are based on the accuracy of the representations made by us.

Notwithstanding the above, and for the reasons described below, Latham & Watkins LLP has not rendered an opinion with respect to the following specific federal income tax issues: (i) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please read "—Tax Consequences of Unit Ownership—Treatment of Short Sales"); (ii) whether all aspects of our method for allocating taxable income and losses is permitted by existing Treasury Regulations (please read "—Disposition of Common Units—Allocations Between Transferors and Transferees"); (iii) whether our method for taking into account Section 743 adjustments is sustainable in certain cases (please read "—Tax Consequences of Unit Ownership—Section 754 Election" and "—Uniformity of Units"); and (iv) whether percentage depletion will be available to a unitholder or the extent of the percentage depletion deduction (please read "—Tax Treatment of Operations—Depletion Deductions").

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable to the partnership or the partner unless the amount of cash distributed to him is in excess of the partner's adjusted basis in his partnership interest.

Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the "Qualifying Income Exception," exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the exploration, development, mining or production, processing, refining, transportation and marketing of certain minerals and natural resources, including crude oil, natural gas and other products of a type that are produced in a petroleum refinery or natural gas processing plant, certain related hedging activities, certain activities that are intrinsic to other qualifying activities, and our allocable share of our subsidiaries' income from these sources. Other types of qualifying income include interest (other than from a financial business), dividends, real property rents, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than % of our current gross income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, the factual representations made by us and our general partner and a review of the applicable legal authorities, Latham & Watkins LLP is of the opinion that at least 90% of our current gross income constitutes qualifying income. The portion of our income that is qualifying income may change from time to time.

The IRS has made no determination as to our status or the status of our operating subsidiaries for federal income tax purposes or whether our operations generate "qualifying income" under Section 7704 of the Internal Revenue Code. Instead, we will rely on the opinion of Latham & Watkins LLP on such matters. It is the opinion of Latham & Watkins LLP that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions and the representations described below that:

- We will be classified as a partnership for federal income tax purposes; and
- Each of our operating subsidiaries will be treated as a partnership or will be disregarded as an entity separate from us for federal income tax purposes.

In rendering its opinion, Latham & Watkins LLP has relied on factual representations made by us and our general partner. The representations made by us and our general partner upon which Latham & Watkins LLP has relied include:

- Neither we nor any of the operating subsidiaries has elected or will elect to be treated, or is otherwise treated, as a corporation for federal income tax purposes;
- For each taxable year, more than 90% of our gross income has been and will be income of the type that Latham & Watkins LLP has opined or will opine is "qualifying income" within the meaning of Section 7704(d) of the Internal Revenue Code; and
- Each commodity hedging transaction that we treat as resulting in qualifying income has been and will be appropriately identified as a hedging transaction pursuant to the applicable Treasury Regulations, and has been and will be associated with oil, gas or products thereof that are held or to be held by us in activities of a type that Latham & Watkins LLP has opined or will opine result in qualifying income.

We believe that these representations have been true in the past, are true as of the date hereof and expect that these representations will continue to be true in the future.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery (in which case the IRS may also require us to make adjustments with respect to our unitholders or pay other amounts), we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in us. This deemed contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

In addition, our general partner may, without unitholder approval, reorganize and cause us to be treated as an entity taxable as a corporation for U.S. federal income tax purposes or cause common units held by unitholders other than the general partner and its affiliates to be converted into or exchanged for interests in a newly formed entity taxed as a corporation for U.S. federal income tax purposes whose sole asset is interests in us. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. Please read "The Partnership Agreement—Election to be Treated as a Corporation."

If we were treated as an association taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to our unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as taxable dividend income, to the extent of our current and accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable capital gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on Latham & Watkins LLP's opinion that we will be classified as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders of TXO Energy Partners will be treated as partners of TXO Energy Partners for federal income tax purposes. Also, unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units will be treated as partners of TXO Energy Partners for federal income tax purposes.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please read "—Tax Consequences of Unit Ownership—Treatment of Short Sales."

Income, gains, losses or deductions would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore appear to be fully taxable as ordinary income. These holders are urged to consult their tax advisors with respect to the tax consequences to them of holding common units in TXO Energy Partners. The references to "unitholders" in the discussion that follows are to persons who are treated as partners in TXO Energy Partners for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income

Subject to the discussion below under "—Entity-Level Collections," we will not pay any federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether we make cash distributions to him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year. Our taxable year ends on December 31.

Treatment of Distributions

Distributions by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes, except to the extent the amount of any such cash distribution exceeds his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under "—Disposition of Common Units." Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution by us of cash to that unitholder. To the extent our distributions cause a unitholder's "at-risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read "—Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. This deemed distribution may constitute a non-pro rata distribution. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture, depletion recapture, intangible drilling costs and/or substantially appreciated "inventory items," each as defined in the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, the unitholder will be treated as having been distributed his proportionate share of the Section 751 Assets and then having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (i) the non-pro rata portion of that distribution over (ii) the unitholder's tax basis (often zero) for the share of Section 751 Assets deemed relinquished in the exchange.

Ratio of taxable income to distributions

We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through the record date for distributions for the year ending December 31, 2025, will be allocated, on a cumulative basis, an amount of U.S. federal taxable income for that period that will be % or less of the cash distributed with respect to that period. Thereafter, we anticipate that the ratio of allocable taxable income to cash distributions to the unitholders will increase. Our estimate is based upon many assumptions regarding our business operations, including assumptions as to our revenues, capital expenditures, cash flow, net working capital and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that these estimates will prove to be correct.

The actual ratio of allocable taxable income to cash distributions could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units. For example, the ratio of allocable taxable income to cash distributions to a purchaser of common units in this offering will be higher, and perhaps substantially higher, than our estimate with respect to the period described above if:

- gross income from operations exceeds the amount required to make quarterly cash distributions from our available cash on all units, yet we only distribute the quarterly cash distributions from our available cash on all units;

- we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering or to acquire property that is not eligible for depletion, depreciation or amortization for U.S. federal income tax purposes or that is depletable, depreciable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this offering; or

- legislation is enacted that limits or repeals certain U.S. federal income tax preferences currently available to oil and gas exploration and production companies (please read "—Recent Legislative Developments").

Basis of Common Units.

A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income, by any increases in his share of our nonrecourse liabilities and, on the disposition of a common unit, by his share of certain items related to business interest not yet deductible by him due to applicable limitations. Please read "—Limitations on Interest Deductions." That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by depletion deductions taken by him to the extent such deductions do not exceed his proportionate share of the adjusted tax basis of the underlying properties, by any decreases in his share of our nonrecourse liabilities, by his share of our excess business interest (generally, the excess of our business interest over the amount that is deductible) and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please read "—Disposition of Common Units—Recognition of Gain or Loss."

Limitations on Deductibility of Losses

The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder, estate, trust, or corporate unitholder (if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by or for five or fewer individuals or some tax-exempt organizations) to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A common unitholder subject to these limitations must recapture losses deducted in previous years to the extent that distributions cause his at-risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such common unitholder's tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at-risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at-risk limitation in excess of that gain would no longer be utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by (i) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or other similar arrangement and (ii) any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder's at-risk amount will increase or decrease as the tax basis of the unitholder's units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

The at risk limitation applies on anactivity-by-activity basis, and in the case of oil and natural gas properties, each property is treated as a separate activity. Thus, a taxpayer's interest in each oil or natural gas property is generally required to be treated separately so that a loss from any one property would be limited to the at risk amount for that property and not the at risk amount for all the taxpayer's oil and natural gas properties. It is uncertain how this rule is implemented in the case of multiple oil and natural gas properties owned by a single entity treated as a partnership for federal income tax purposes. However, for taxable years ending on or before the date on which further guidance is published, the IRS will permit aggregation of oil or natural gas properties we own in computing a unitholder's at risk limitation with respect to us. If a unitholder were required to compute his at risk amount separately with respect to each oil or natural gas property we own, he might not be allowed to utilize his share of losses or deductions attributable to a particular property even though he has a positive at risk amount with respect to his common units as a whole.

In addition to the basis and at-risk limitations on the deductibility of losses, the passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally trade or business activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or a unitholder's investments in other publicly traded partnerships, or the unitholder's salary, active business or other income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive loss limitations are applied after other applicable limitations on deductions, including the at-risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

An additional loss limitation may apply to certain of our unitholders for taxable years ending before January 1, 2026. A non-corporate unitholder will not be allowed to take a deduction for certain excess business losses in such taxable years. An excess business loss is the excess (if any) of a taxpayer's aggregate deductions for the taxable year that are attributable to the trades or businesses of such taxpayer (determined without regard to the excess business loss limitation or any deduction allowable for net operating losses, qualified business income or capital losses) over the aggregate gross income or gain of such taxpayer for the taxable year that is attributable to such trades or businesses (subject to certain limitations in the case of capital gains) plus a threshold amount. The current threshold amount is equal to $270,000, or $550,000 for taxpayers filing a joint return. Any losses disallowed in a taxable year due to the excess business loss limitation may be used by the applicable unitholder in the following taxable year if certain conditions are met. Unitholders to which this excess business loss limitation applies will take their allocable share of our items of income, gain, loss and deduction into account in determining this limitation. This excess business loss limitation will be applied to a non-corporate unitholder after the passive loss limitations and may limit such unitholders' ability to utilize any losses we generate allocable to such unitholder that are not otherwise limited by the basis, at-risk and passive loss limitations described above.

Limitations on Interest Deductions

Our ability to deduct interest paid or accrued on indebtedness properly allocable to a trade or business, "business interest", may be limited in certain circumstances. Should our ability to deduct business interest be limited, the amount of taxable income allocated to our unitholders in the taxable year in which the limitation is in effect may increase. However, in certain circumstances, a unitholder may be able to utilize a portion of a business interest deduction subject to this limitation in future taxable years. Prospective unitholders should consult their tax advisors regarding the impact of this business interest deduction limitation on an investment in our common units.

In addition, the deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;

- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment or (if applicable) qualified dividend income. The IRS has indicated that the net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, the unitholder's share of our portfolio income will be treated as investment income.

Entity-Level Collections

If we are required or elect under applicable law to pay any federal, state, local or foreign income tax on behalf of any unitholder or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the unitholder on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend our partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under our partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual unitholder in which event the unitholder would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction

In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among the common unitholders in accordance with their percentage interests in us. If we have a net loss, that loss will be allocated to the common unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts, as adjusted for certain items in accordance with applicable Treasury Regulations.

Specified items of our income, gain, loss and deduction will be allocated to account for (i) any difference between the tax basis and fair market value of our assets at the time of this offering and (ii) any difference between the tax basis and fair market value of any property contributed to us that exists at the time of such contribution, together referred to in this discussion as the "Contributed Property." The effect of these allocations, referred to as Section 704(c) Allocations, to a unitholder purchasing common units from us in this offering will be essentially the same as if the tax bases of our assets were equal to their fair market values at the time of this offering. In the event we issue additional common units or engage in certain other transactions in the future, "reverse Section 704(c) Allocations," similar to the Section 704(c) Allocations described above, will be made to all of our common unitholders immediately prior to such issuance or other transactions to account for the difference between the "book" basis for purposes of maintaining capital accounts and the fair market value of all property held by us at the time of such issuance or future transaction. However, it may not be administratively feasible to make the relevant adjustments to "book" basis and the relevant reverse Section 704(c) Allocations each time we issue common units, particularly in the case of small or frequent common unit issuances. If that is the case, we may use simplifying conventions to make those adjustments and allocations, which may include the aggregation of certain issuances of common units. Latham & Watkins LLP is unable to opine as to the validity of such conventions. In addition, items of recapture income will be allocated to the extent possible to the unitholder who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts (subject to certain adjustments), if negative capital accounts (subject to certain adjustments) nevertheless result, items of our income and gain will be allocated in an amount and manner sufficient to eliminate such negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Internal Revenue Code to eliminate the difference between a partner's "book" capital account, credited with the fair market value of Contributed Property, and "tax" capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the "Book-Tax Disparity," will generally be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has "substantial economic effect." In any other case, a partner's share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the partners in profits and losses;
- the interest of all the partners in cash flow; and
- the rights of all the partners to distributions of capital upon liquidation.

Latham & Watkins LLP is of the opinion that, with the exception of the issues described in "—Section 754 Election" and "—Disposition of Common Units—Allocations Between Transferors and Transferees," allocations under our partnership agreement will be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction.

Treatment of Short Sales

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

As a result, during this period:

- any of our income, gain, loss or deduction with respect to those units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those units would be fully taxable; and
- while not entirely free from doubt, all of these distributions would appear to be ordinary income.

Because there is no direct or indirect controlling authority on the issue relating to partnership interests, Latham & Watkins LLP has not rendered an opinion regarding the tax treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their units. The IRS has previously announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please also read "—Disposition of Common Units—Recognition of Gain or Loss."

Tax Rates

Currently, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 37% and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, capital gains on certain assets held for more than twelve months) of individuals is 20%. Such rates are subject to change by new legislation at any time.

In addition, a 3.8% Medicare tax, or NIIT, is imposed on certain net investment income earned by individuals, estates and trusts. For these purposes, net investment income generally includes a unitholder's allocable share of our income and gain realized by a unitholder from a sale of units. In the case of an individual, the tax will be imposed on the lesser of (i) the unitholder's net investment income or (ii) the amount by which the unitholder's modified adjusted gross income exceeds $250,000 (if the unitholder is married and filing jointly or a surviving spouse), $125,000 (if the unitholder is married and filing separately) or $200,000 (in any other case). In the case of an estate or trust, the tax will be imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins for such taxable year. The U.S. Department of the Treasury and the IRS have issued Treasury Regulations that provide guidance regarding the NIIT. Prospective common unitholders are urged to consult with their tax advisors as to the impact of the NIIT on an investment in our common units.

For taxable years ending on or before December 31, 2025, anon-corporate unitholder is entitled to a deduction equal to 20% of its "qualified business income" attributable to us, subject to certain limitations. For purposes of this deduction, a unitholder's "qualified business income" attributable to us is equal to the sum of:

- the net amount of such unitholder's allocable share of certain of our items of income, gain, deduction and loss (generally excluding certain items related to our investment activities, including capital gains and dividends, which are subject to a federal income tax rate of 20%); and

- any gain recognized by such unitholder on the disposition of its units to the extent such gain is attributable to certain Section 751 assets, including depreciation recapture and "inventory items" we own.

Prospective unitholders should consult their tax advisors regarding the application of this deduction and its interaction with the overall deduction for qualified business income.

Section 754 Election

We have made the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election generally permits us to adjust a common unit purchaser's tax basis in our assets ("inside basis") under Section 743(b) of the Internal Revenue Code to reflect his purchase price. This election does not apply with respect to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, the inside basis in our assets with respect to a unitholder will be considered to have two components: (i) his share of our tax basis in our assets ("common basis") and (ii) his Section 743(b) adjustment to that basis.

We have adopted or will adopt the remedial allocation method as to all our properties. Where the remedial allocation method is adopted, the Treasury Regulations under Section 743 of the Internal Revenue Code require a portion of the Section 743(b) adjustment that is attributable to recovery property that is subject to depreciation under Section 168 of the Internal Revenue Code and whose book basis is in excess of its tax basis to be depreciated over the remaining cost recovery period for the property's unamortized Book-Tax Disparity. Under Treasury Regulation Section 1.167(c)-1(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code, rather than cost recovery deductions under Section 168, is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our partnership agreement, our general partner is authorized to take a position to preserve the uniformity of units even if that position is not consistent with these and any other Treasury Regulations. Please read "—Uniformity of Units."

We will depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as non-amortizable to the extent attributable to property that is not amortizable. This method is consistent with the methods employed by other publicly traded partnerships but is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please read "—Uniformity of Units." A unitholder's tax basis for his common units is reduced by his share of our deductions (whether or not such deductions were claimed on an individual's income tax return) so that any position we take that understates deductions will overstate such unitholder's basis in his common units, which may cause the unitholder to understate gain or overstate loss on any sale of such units. Please read "—Disposition of Common Units—Recognition of Gain or Loss." Latham & Watkins LLP is unable to opine as to whether our method for taking into account Section 743 adjustments is sustainable for property subject to depreciation under Section 167 of the Internal Revenue Code or if we use an aggregate approach as described above, as there is no direct or indirect controlling authority addressing the validity of these positions. Moreover, the IRS may challenge our position with respect to depreciating or amortizing the Section 743(b) adjustment we take to preserve the uniformity of the units. If such a challenge were sustained, the gain from the sale of units might be increased without the benefit of additional deductions.

Subject to certain limitations, a Section 743(b) adjustment may create additional depreciable basis that is eligible for bonus depreciation under Section 168(k) to the extent the adjustment is attributable to depreciable property and not to goodwill or real property. However, because we may not be able to determine whether transfers of our units satisfy all of the eligibility requirements and due to other limitations regarding administrability, we may elect out of the bonus depreciation provisions of Section 168(k) with respect to basis adjustments under Section 743(b).

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer. Generally, a built-in loss is substantial if (i) it exceeds $250,000 or (ii) the transferee would be allocated a net loss in excess of $250,000 on a hypothetical sale of our assets for their fair market value immediately after a transfer of the interests at issue. In addition, a basis adjustment is required regardless of whether a Section 754 election is made if we distribute property and have a substantial basis reduction. A substantial basis reduction exists if, on a liquidating distribution of property to a unitholder, there would be a negative basis adjustment to our assets in excess of $250,000 if a Section 754 election were in place.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally nonamortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year

We will use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than twelve months of our income, gain, loss and deduction. Please read "—Disposition of Common Units—Allocations Between Transferors and Transferees."

Depletion Deductions

Subject to the limitations on deductibility of losses discussed above (please read "—Tax Consequences of Unit Ownership—Limitations on Deductibility of Losses"), unitholders will be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to our oil and natural gas interests. Although the Internal Revenue Code requires each unitholder to compute his own depletion allowance and maintain records of his share of the adjusted tax basis of the underlying property for depletion and other purposes, we intend to furnish each of our unitholders with information relating to this computation for federal income tax purposes. Each unitholder, however, remains responsible for calculating his own depletion allowance and maintaining records of his share of the adjusted tax basis of the underlying property for depletion and other purposes.

Percentage depletion is generally available with respect to unitholders who qualify under the independent producer exemption contained in Section 613A(c) of the Internal Revenue Code. To qualify as an "independent producer" eligible for percentage depletion (and that is not subject to the intangible drilling and development cost deduction limits, please read "—Deductions for Intangible Drilling and Development Costs"), a unitholder, either directly or indirectly through certain related parties, may not be involved in the refining of more than 75,000 barrels of oil (or the equivalent amount of natural gas) on average for any day during the taxable year or in the retail marketing of oil and natural gas products exceeding $5.0 million per year in the aggregate. Percentage depletion is calculated as an amount generally equal to 15% (and, in the case of marginal production, potentially a higher percentage) of the unitholder's gross income from the depletable property for the taxable year. The percentage depletion deduction with respect to any property is limited to 100% of the taxable income of the unitholder from the property for each taxable year, computed without the depletion allowance. A unitholder that qualifies as an independent producer may deduct percentage depletion only to the extent the unitholder's average net daily production of domestic crude oil, or the natural gas equivalent, does not exceed 1,000 barrels. This depletable amount may be allocated between oil and natural gas production, with 6,000 cubic feet of domestic natural gas production regarded as equivalent to one barrel of crude oil. The 1,000-barrel limitation must be allocated among the independent producer and controlled or related persons and family members in proportion to the respective production by such persons during the period in question.

In addition to the foregoing limitations, the percentage depletion deduction otherwise available is limited to 65% of a unitholder's total taxable income from all sources for the year, computed without the depletion allowance, net operating loss carrybacks, or capital loss carrybacks. Any percentage depletion deduction disallowed because of the 65% limitation may be deducted in the following taxable year if the percentage depletion deduction for such year plus the deduction carryover does not exceed 65% of the unitholder's total taxable income for that year. The carryover period resulting from the 65% net income limitation is unlimited.

Unitholders that do not qualify under the independent producer exemption are generally restricted to depletion deductions based on cost depletion. Cost depletion deductions are calculated by (i) dividing the unitholder's share of the adjusted tax basis in the underlying mineral property by the number of mineral common units (barrels of oil and thousand cubic feet, or Mcf, of natural gas) remaining as of the beginning of the taxable year and (ii) multiplying the result by the number of mineral common units sold within the taxable year. The total amount of deductions based on cost depletion cannot exceed the unitholder's share of the total adjusted tax basis in the property.

All or a portion of any gain recognized by a unitholder as a result of either the disposition by us of some or all of our oil and natural gas interests or the disposition by the unitholder of some or all of his common units may be taxed as ordinary income to the extent of recapture of depletion deductions, except for percentage depletion deductions in excess of the tax basis of the property. The amount of the recapture is generally limited to the amount of gain recognized on the disposition.

The foregoing discussion of depletion deductions does not purport to be a complete analysis of the complex legislation and Treasury Regulations relating to the availability and calculation of depletion deductions by the unitholders. Further, because depletion is required to be computed separately by each unitholder and not by our partnership, no assurance can be given, and counsel is unable to express any opinion, with respect to the availability or extent of percentage depletion deductions to the unitholders for any taxable year. Moreover, the availability of percentage depletion may be reduced or eliminated if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read "—Recent Legislative Developments." We encourage each prospective unitholder to consult his tax advisor to determine whether percentage depletion would be available to him.

Deductions for Intangible Drilling and Development Costs

We will elect to currently deduct intangible drilling and development costs, or IDCs. IDCs generally include our expenses for wages, fuel, repairs, hauling, supplies and other items that are incidental to, and necessary for, the drilling and preparation of wells for the production of oil, natural gas, or geothermal energy. The option to currently deduct IDCs applies only to those items that do not have a salvage value.

Although we will elect to currently deduct IDCs, each unitholder will have the option of either currently deducting IDCs or capitalizing all or part of the IDCs and amortizing them on a straight-line basis over a 60-month period, beginning with the taxable month in which the expenditure is made. If a non-corporate unitholder makes the election to amortize the IDCs over a60-month period, no IDC preference amount in respect of those IDCs will result for alternative minimum tax purposes.

Integrated oil companies must capitalize 30% of all their IDCs (other than IDCs paid or incurred with respect to oil and natural gas wells located outside of the United States) and amortize these IDCs over 60 months beginning in the month in which those costs are paid or incurred. If the taxpayer ceases to be an integrated oil company, it must continue to amortize those costs as long as it continues to own the property to which the IDCs relate. An "integrated oil company" is a taxpayer that has economic interests in oil or natural gas properties and also carries on substantial retailing or refining operations. An oil or natural gas producer is deemed to be a substantial retailer or refiner if it is does not qualify as an independent producer under the rules disqualifying retailers and refiners from taking percentage depletion. Please read "—Depletion Deductions."

IDCs previously deducted that are allocable to property (directly or through ownership of an interest in a partnership) and that would have been included in the adjusted tax basis of the property had the IDC deduction not been taken are recaptured to the extent of any gain realized upon the disposition of the property or upon the disposition by a unitholder of interests in us. Recapture is generally determined at the unitholder level. Where only a portion of the recapture property is sold, any IDCs related to the entire property are recaptured to the extent of the gain realized on the portion of the property sold. In the case of a disposition of an undivided interest in a property, a proportionate amount of the IDCs with respect to the property is treated as allocable to the transferred undivided interest to the extent of any gain recognized. Please read "—Disposition of Common Units—Recognition of Gain or Loss."

The election to currently deduct IDCs may be restricted or eliminated if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read "—Recent Legislative Developments."

Lease Acquisition Costs

The cost of acquiring oil and natural gas lease or similar property interests is a capital expenditure that must be recovered through depletion deductions if the lease is productive. If a lease is proved worthless and abandoned, the cost of acquisition less any depletion claimed may be deducted as an ordinary loss in the year the lease becomes worthless. Please read "—Depletion Deductions."

Geophysical Costs

The cost of geophysical exploration incurred in connection with the exploration and development of oil and natural gas properties in the United States are deducted ratably over a 24-month period beginning on the date that such expense is paid or incurred. The amortization period for certain geological and geophysical expenditures may be extended if recently proposed (or similar) tax legislation is enacted. For a discussion of such legislative proposals, please read "—Recent Legislative Developments."

Operating and Administrative Costs

Amounts paid for operating a producing well are deductible as ordinary business expenses, as are administrative costs, to the extent they constitute ordinary and necessary business expenses that are reasonable in amount.

Tax Basis, Depreciation and Amortization

The tax basis of our assets will be used for purposes of computing depreciation, depletion and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to an offering will be borne by our unitholders holding interests in us prior to any such offering. Please read "— Tax Consequences of Unit Ownership—Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may use the depreciation and cost recovery methods, including bonus depreciation to the extent available, that will result in the largest deductions being taken in the early years after assets subject to these allowances are placed in service. Please read "—Uniformity of Units." Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable or depletable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation and depletion previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery, depletion or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please read "—Tax Consequences of Unit Ownership—Allocation of Income, Gain, Loss and Deduction" and "—Disposition of Common Units—Recognition of Gain or Loss."

The costs we incur in selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and Tax Basis of our Properties

The U.S. federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values, and the initial tax bases, of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or determinations of basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss

Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us that in the aggregate were in excess of cumulative net taxable income for a common unit and, therefore, decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a "dealer" in units, on the sale or exchange of a unit will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held for more than twelve months will generally be taxed at the U.S. federal income tax rate applicable to long-term capital gains. However, a portion of this gain or loss, which will likely be substantial, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to "unrealized receivables," including potential recapture items such as depreciation, depletion, or IDC recapture, or to "inventory items" we own. Ordinary income attributable to unrealized receivables and inventory items may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of units. Capital losses may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations. Ordinary income recognized by a unitholder on disposition of our units may be reduced by such unitholder's deduction for qualified business income. Both ordinary income and capital gain recognized on a sale of units may be subject to the NIIT in certain circumstances. Please read "—Tax Consequences of Unit Ownership—Tax Rates."

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in his entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership. Treasury Regulations under Section 1223 of the Internal Revenue Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling discussed above, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the Treasury Regulations, he may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the Treasury Regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract;

in each case, with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations between Transferors and Transferees

In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis in proportion to the number of days in each month and will be subsequently apportioned among our unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month, which we refer to in this prospectus as the "Allocation Date." However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among our unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

The U.S. Department of Treasury and the IRS have issued Treasury Regulations that permit publicly traded partnerships to use a monthly simplifying convention that is similar to ours, but they do not specifically authorize all aspects of the proration method we have adopted. Accordingly, Latham & Watkins LLP is unable to opine on the validity of this method of allocating income and deductions between transferor and transferee unitholders. If this method is not allowed under the Treasury Regulations, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between transferor and transferee unitholders, as well as unitholders whose interests vary during a taxable year.

A unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter through the month of disposition but will not be entitled to receive that cash distribution.

Notification Requirements

A unitholder who sells any of his units is generally required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of units who purchases units from another unitholder is also generally required to notify us in writing of that purchase within 30 days after the purchase. Upon receiving such notifications, we are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a purchase may, in some cases, lead to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker who will satisfy such requirements.

Uniformity of Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please read "—Tax Consequences of Unit Ownership—Section 754 Election."

We depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the regulations under Section 743 of the Internal Revenue Code, even though that position may be inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. Please read "—Tax Consequences of Unit Ownership—Section 754 Election." To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. If this position is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. In either case, and as stated above under "—Tax Consequences of Unit Ownership—Section 754 Election," Latham & Watkins LLP has not rendered an opinion with respect to these methods. Moreover, the IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please read "—Disposition of Common Units —Recognition of Gain or Loss."

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other foreign persons raises issues unique to those investors and, as described below to a limited extent, may have substantially adverse tax consequences to them. If you are a tax-exempt entity or a foreign person, you should consult your tax advisor before investing in our common units.

Employee benefit plans and most other organizations exempt from federal income tax, including IRAs and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to it. Further, a tax-exempt organization with more than one unrelated trade or business (including by attribution from investments in a partnership, such as us, that is engaged in one or more unrelated trades or businesses) must compute its unrelated business taxable income separately for each such trade or business, including for purposes of determining any net operating loss deduction. As a result, it may not be possible for tax-exempt organizations to use losses from an investment in us to offset taxable income from another unrelated trade or business.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States because of the ownership of units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay U.S. federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, our quarterly distribution to foreign unitholders will be subject to withholding at the highest applicable effective tax rate. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN, W-8BEN-E or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns units will be treated as engaged in a U.S. trade or business, that corporation may be subject to the U.S. branch profits tax at a rate of 30%, in addition to regular U.S. federal income tax, on its share of our earnings and profits, as adjusted for changes in the foreign corporation's "U.S. net equity," that is effectively connected with the conduct of a U.S. trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

A foreign unitholder who sells or otherwise disposes of a common unit will be subject to U.S. federal income tax on gain realized from the sale or disposition of that unit to the extent the gain is effectively connected with a U.S. trade or business of the foreign unitholder. Gain on the sale or disposition of a common unit will be treated as effectively connected with a U.S. trade or business to the extent that a foreign unitholder would recognize gain effectively connected with a U.S. trade or business upon the hypothetical sale of our assets at fair market value on the date of the sale or exchange of that unit. Such gain shall be reduced by certain amounts treated as effectively connected with a U.S. trade or business attributable to certain real property interests, as set forth in the following paragraph.

Under the Foreign Investment in Real Property Tax Act, a foreign common unitholder (other than certain "qualified foreign pension funds" (or an entity all of the interests of which are held by such a qualified foreign pension fund), which generally are entities or arrangements that are established and regulated by foreign law to provide retirement or other pension benefits to employees, do not have a single participant or beneficiary that is entitled to more than 5% of the assets or income of the entity or arrangement and are subject to certain preferential tax treatment under the laws of the applicable foreign country), generally will be subject to U.S. federal income tax upon the sale or disposition of a common unit if (i) he owned (directly or constructively applying certain attribution rules) more than 5% of our common units at any time during the five-year period ending on the date of such disposition and (ii) 50% or more of the fair market value of all of our assets consisted of U.S. real property interests at any time during the shorter of the period during which such unitholder held the common units or the five-year period ending on the date of disposition. Currently, more than 50% of our assets consist of U.S. real property interests and we do not expect that to change in the foreseeable future.

Therefore, foreign unitholders may be subject to U.S. federal income tax on gain from the sale or disposition of their units.

Upon the sale, exchange or other disposition of a common unit by a foreign unitholder, the transferee is generally required to withhold 10% of the amount realized on such sale, exchange or other disposition if any portion of the gain on such sale, exchange or other disposition would be treated as effectively connected with a U.S. trade or business. The U.S. Department of the Treasury and the IRS have issued final regulations providing guidance on the application of these rules for transfers of certain publicly traded partnership interests, including transfers of our common units. Under these regulations, the "amount realized" on a transfer of our common units will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and such broker will generally be responsible for the relevant withholding obligations. Quarterly distributions made to our foreign unitholders may also be subject to withholding under these rules to the extent a portion of a distribution is attributable to an amount in excess of our cumulative net income that has not previously been distributed. The U.S. Department of the Treasury and the IRS have provided that these rules will generally not apply to transfers of, or distributions on, our common units occurring before January 1, 2023. Prospective foreign unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

Additional withholding requirements may also affect certain foreign unitholders. Please read "—Administrative Matters—Additional Withholding Requirements."

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a ScheduleK-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder's share of income, gain, loss and deduction. We cannot assure you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Neither we nor Latham & Watkins LLP can assure prospective common unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Similarly, for such taxable years, if the IRS makes audit adjustments to income tax returns filed by an entity in which we are a member or a partner, it may assess and collect any taxes (including penalties and interest) resulting from such audit adjustment directly from such entity. Generally, we expect to elect to have our unitholders and former unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be effective in all circumstances. If we are unable to have our unitholders and former unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own our units during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our common unitholders might be substantially reduced.

Additionally, pursuant to the Bipartisan Budget Act of 2015, we are required to designate a partner, or other person, with a substantial presence in the United States as the partnership representative ("Partnership Representative"). The Partnership Representative has the sole authority to act on our behalf for purposes of, among other things, U.S. federal income tax audits and judicial review of administrative adjustments by the IRS. If we do not make such a designation, the IRS can select any person as the Partnership Representative. We currently anticipate that we will designate our general partner as our Partnership Representative. Further, any actions taken by us or by the Partnership Representative on our behalf with respect to, among other things, U.S. federal income tax audits and judicial review of administrative adjustments by the IRS, will be binding on us and all of our unitholders.

Additional Withholding Requirements

Withholding taxes may apply to certain types of payments made to "foreign financial institutions" (as specially defined in the Internal Revenue Code) and certain other foreign entities. Specifically, a 30% withholding tax may be imposed on interest, dividends and other fixed or determinable annual or periodical gains, profits and income from sources within the United States ("FDAP Income"), or, subject to the proposed Treasury Regulations discussed below, gross proceeds from the sale or other disposition of any property of a type that can produce interest or dividends from sources within the United States ("Gross Proceeds") paid to a foreign financial institution or to a "non-financial foreign entity" (as specially defined in the Internal Revenue

Code), unless (i) the foreign financial institution undertakes certain diligence and reporting, (ii) the non-financial foreign entity either certifies it does not have any substantial U.S. owners or furnishes identifying information regarding each substantial U.S. owner or (iii) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules. If the payee is a foreign financial institution and is subject to the diligence and reporting requirements in clause (i) above, it must enter into an agreement with the U.S. Department of the Treasury requiring, among other things, that it undertake to identify accounts held by certain U.S. persons or U.S.-owned foreign entities, annually report certain information about such accounts, and withhold 30% on payments to noncompliant foreign financial institutions and certain other account holders. Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing these requirements may be subject to different rules.

These rules generally apply to payments of FDAP Income currently and, while these rules generally would have applied to payments of relevant Gross Proceeds made on or after January 1, 2019, proposed Treasury Regulations eliminate these withholding taxes on payments of Gross Proceeds entirely. Unitholders generally may rely on these proposed Treasury Regulations until final Treasury Regulations are issued. Thus, to the extent we have FDAP Income that is not treated as effectively connected with a U.S. trade or business (please read "—Tax-Exempt Organizations and Other Investors"), unitholders who are foreign financial institutions or certain other foreign entities, or persons that hold their common units through such foreign entities, may be subject to withholding on distributions they receive from us, or their distributive share of our income, pursuant to the rules described above.

Prospective common unitholders should consult their own tax advisors regarding the potential application of these withholding provisions to their investment in our common units.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- whether the beneficial owner is:
  - a person that is not a U.S. person;
  - a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or
  - a tax-exempt entity;
- the amount and description of units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from dispositions.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $290 per failure, up to a maximum of $3,532,500 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-Related Penalties

Certain penalties may be imposed on taxpayers as a result of an underpayment of tax that is attributable to one or more specified causes, including: (i) negligence or disregard of rules or regulations, (ii) substantial understatements of income tax, (iii) substantial valuation misstatements and (iv) the disallowance of claimed tax benefits by reason of a transaction lacking economic substance or failing to meet the requirements of any similar rule of law. Except with respect to the disallowance of claimed tax benefits by reason of a transaction lacking economic substance or failing to meet the requirements of any similar rule of law, however, no penalty will be imposed for any portion of any such underpayment if it is shown that there was a reasonable cause for the underpayment of that portion and that the taxpayer acted in good faith regarding the underpayment of that portion.

With respect to substantial understatements of income tax, the amount of any understatement subject to penalty generally is reduced by that portion of the understatement which is attributable to a position adopted on the return: (A) for which there is, or was, "substantial authority"; or (B) as to which there is a reasonable basis and the relevant facts of that position are adequately disclosed on the return.

If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an "understatement" of income for which no "substantial authority" exists, we must adequately disclose the relevant facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit unitholders to avoid liability for this penalty.

Recent Legislative Developments

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of Congress and the President propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships, including the elimination of partnership tax treatment for publicly traded partnerships.

In recent years, legislation has been proposed that would reduce or eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Changes in such proposals include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our common units.

Any modification to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for federal income tax purposes. Please read "—Partnership Status". We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us, and any such changes could negatively impact the value of an investment in our common units.

State, Local, Foreign and Other Tax Considerations

In addition to federal income taxes, you will likely be subject to other taxes, such as state, local and foreign income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective common unitholder should consider their potential impact on his investment in us. We expect initially to own property or do business in New Mexico, Texas and Colorado. New Mexico and Colorado each impose a personal income tax. Texas does not currently impose a personal income tax on individuals, but it does impose an entity level tax (to which we will be subject) on corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you will be required to file income tax returns and to pay income taxes in many of these jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. Some of the jurisdictions may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the jurisdiction. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the jurisdiction, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld will be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please read "—Tax Consequences of Unit Ownership—Entity-Level Collections." Based on current law and our estimate of our future operations, our general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent states, localities and foreign jurisdictions, of his investment in us. Accordingly, each prospective common unitholder is urged to consult his own tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and foreign, as well as U.S. federal tax returns, that may be required of him. Latham & Watkins LLP has not rendered an opinion on the state tax, local tax, alternative minimum tax or foreign tax consequences of an investment in us.

INVESTMENT IN TXO ENERGY PARTNERS BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and the restrictions imposed by Section 4975 of the Internal Revenue Code and provisions under any federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of the Internal Revenue Code or ERISA (collectively, "Similar Laws"). For these purposes the term "employee benefit plan" includes, but is not limited to, qualified pension, profit-sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or individual retirement accounts or annuities ("IRAs") established or maintained by an employer or employee organization, and entities whose underlying assets are considered to include "plan assets" of such plans, accounts and arrangements (collectively, "Employee Benefit Plans"). Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA and any other applicable Similar Laws;
- whether in making the investment, the plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws;
- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return. Please read "Material U.S. Federal Income Tax Consequences—Tax-Exempt Organizations and Other Investors"; and
- whether making such an investment will comply with the delegation of control and prohibited transaction provisions of ERISA, the Internal Revenue Code and any other applicable Similar Laws.

The person with investment discretion with respect to the assets of an Employee Benefit Plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit Employee Benefit Plans, and IRAs that are not considered part of an Employee Benefit Plan, from engaging, either directly or indirectly, in specified transactions involving "plan assets" with parties that, with respect to the plan, are "parties in interest" under ERISA or "disqualified persons" under the Internal Revenue Code unless an exemption is available. A party in interest or disqualified person who engages in a non-exempt prohibited transaction may be subject to excise taxes and other penalties and liabilities under ERISA and the Internal Revenue Code. In addition, the fiduciary of the ERISA plan that engaged in such a non-exempt prohibited transaction may be subject to penalties and liabilities under ERISA and the Internal Revenue Code.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that our general partner would also be a fiduciary of such plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code, ERISA and any other applicable Similar Laws.

The Department of Labor regulations and Section 3(42) of ERISA provide guidance with respect to whether, in certain circumstances, the assets of an entity in which Employee Benefit

Plans acquire equity interests would be deemed "plan assets." Under these rules, an entity's assets would not be considered to be "plan assets" if, among other things:

- the equity interests acquired by the Employee Benefit Plan are publicly offered securities—i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, are freely transferable and are registered under certain provisions of the federal securities laws;
- the entity is an "operating company,"—i.e., it is primarily engaged in the production or sale of a product or service, other than the investment of capital, either directly or through a majority-owned subsidiary or subsidiaries; or
- there is no significant investment by "benefit plan investors," which is generally defined to mean that less than 25% of the value of each class of equity interest, disregarding any such interests held by our general partner, its affiliates and certain persons, is held by the Employee Benefit Plans.

Our assets should not be considered "plan assets" under these regulations because it is expected that the investment will satisfy the requirements in the first two bullet points above.

In light of the serious penalties imposed on persons who engage in prohibited transactions or other violations, plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA, the Internal Revenue Code and other Similar Laws.

UNDERWRITING

Raymond James & Associates, Inc. is acting as representative of each of the underwriters named below. Subject to the terms and conditions set forth in an underwriting agreement dated the date of this prospectus, we have agreed to sell to the underwriters, and each of the underwriters has agreed, severally and not jointly, to purchase from us, the number of our common units set forth opposite its name below.

Underwriters	Number of Common Units
Raymond James & Associates, Inc.	
Total	

Subject to the terms and conditions set forth in the underwriting agreement, the underwriters have agreed, severally and not jointly, to purchase all of our common units (other than those covered by the underwriters' option to purchase additional common units described below) sold under the underwriting agreement. If an underwriter defaults, the underwriting agreement provides that the purchase commitments of the non-defaulting underwriters may be increased or the underwriting agreement may be terminated.

We have agreed to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act, or to contribute to payments the underwriters may be required to make in respect of those liabilities.

The underwriters are offering our common units, subject to prior sale, when, as and if issued to and accepted by them, subject to approval of legal matters by their counsel, including the validity of the common units, and other conditions contained in the underwriting agreement, such as the receipt by the underwriters of officers' certificates and legal opinions. The underwriters reserve the right to withdraw, cancel or modify offers to the public and to reject orders in whole or in part.

Underwriting Discounts and Expenses

The representative has advised us that the underwriters propose initially to offer our common units to the public at the public offering price set forth on the cover page of this prospectus and to dealers at that price less a concession not in excess of $ per common unit. After this offering, the public offering price, concession or any other term of this offering may be changed.

The following table shows the public offering price, underwriting discount and proceeds before expenses to us. The information assumes either no exercise or full exercise by the underwriters of their option to purchase additional common units.

	Per Unit	Without Option	With Option
Public offering price	$	$	$
Underwriting discount			
Proceeds, before expenses, to us	$	$	$

The estimated expenses of this offering payable by us, exclusive of the underwriting discount, are approximately $. We will reimburse the underwriters for certain reasonable out-of-pocket expenses not to exceed $ in the aggregate.

Over-Allotment Option

We have granted an option to the underwriters to purchase up to an aggregate of additional common units at the public offering price, less the underwriting discount. The underwriters may exercise this option at any time or from time to time for 30 days from the date of this prospectus solely to cover any over-allotments. If the underwriters exercise this option, each will be obligated, subject to conditions contained in the underwriting agreement, to purchase a number of additional common units proportionate to that underwriter's initial amount as reflected in the above table.

No Sales of Similar Securities

The directors and executive officers of our general partner, and their respective affiliates have agreed with the underwriters not to offer, sell, transfer or otherwise dispose of any common units or any securities convertible into or exercisable or, exchangeable for, exercisable for, or repayable with common units, for a period of 180 days after the date of this prospectus without first obtaining the written consent of the representative. Specifically, we and these other persons have agreed, with certain limited exceptions, not to directly or indirectly:

- offer, pledge, sell or contract to sell any common units;
- sell any option or contract to purchase any common units;
- purchase any option or contract to sell any common units;
- grant any option, right or warrant for the sale of any common units;
- lend or otherwise dispose of or transfer any common units;
- file or cause to be filed any registration statement related to the common units; or
- enter into any swap or other agreement that transfers, in whole or in part, the economic consequence of ownership of any common units whether any such swap or other agreement is to be settled by delivery of common units or other securities, in cash or otherwise.

This lock-up provision applies to common units and to securities convertible into or exchangeable or exercisable for or repayable with common units. It also applies to common units owned now or acquired later by the person executing the agreement or for which the person executing the agreement later acquires the power of disposition.

Raymond James & Associates, Inc. may release any of the common units and other securities subject to thelock-up agreements described above in whole or in part subject to the below considerations. When determining whether or not to release common units from lock-up agreements, Raymond James & Associates, Inc. will consider, among other factors, the unitholders' reasons for requesting the release, the number of common units for which the release is being requested and market conditions at the time. However, Raymond James & Associates, Inc. has informed us that, as of the date of this prospectus, there are no agreements between them and any party that would allow such party to transfer any common units, nor do they have any intention at this time of releasing any of the common units subject to the lock-up agreements, prior to the expiration of the lock-up period.

Listing

We have applied to list our common units on the NYSE under the symbol “TXO.” In order to meet the requirements for listing on that exchange, the underwriters will undertake to sell a minimum number of our common units to a minimum number of beneficial owners as required by the NYSE.

Determination of Offering Price

Before this offering, there has been no public market for our common units. The public offering price will be determined through negotiations between us and the representative. In addition to prevailing market conditions, the factors to be considered in determining the public offering price are:

- the information set forth in this prospectus and otherwise available to the underwriters;
- the valuation multiples of publicly traded companies that the representative believes to be comparable to us;
- our financial information;
- the history of, and the prospects for, our company and the industry in which we compete;
- the ability of our management;
- an assessment of our general partner, its past and present operations, and the prospects for, and timing of, our future revenues;
- the present state of our development;
- the above factors in relation to market values and various valuation measures of other companies engaged in activities similar to ours; and
- other factors deemed relevant by the underwriters and us.

An active trading market for our common units may not develop or, if developed, be maintained or be liquid. It is also possible that after this offering our common units will not trade in the public market at or above the public offering price.

The underwriters do not expect to sell more than % of the common units in the aggregate to accounts over which they exercise discretionary authority.

Price Stabilization, Short Positions and Penalty Bids

Until the distribution of our common units is completed, SEC rules may limit underwriters and selling group members from bidding for and purchasing our common units. However, the underwriters may engage in transactions that stabilize the price of the common units, such as bids or purchases to peg, fix or maintain that price.

In connection with this offering, the underwriters may purchase and sell our common units in the open market. These transactions may include short sales, purchases on the open market to cover positions created by short sales and stabilizing transactions. Short sales involve the sale by the underwriters of a greater number of our common units than they are required to purchase in this offering. "Covered" short sales are sales made in an amount not greater than the underwriters' over-allotment option to purchase additional common units described above. The underwriters may close out any covered short position by either exercising their option or purchasing common units in the open market. In determining the source of our common units to close out the covered short position, the underwriters will consider, among other things, the price of our common units available for purchase in the open market as compared to the price at which they may purchase our common units through the option. "Naked" short sales are sales in excess of the over-allotment option. The underwriters must close out any naked short position by purchasing our common units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of our common units in the open market after pricing that could adversely affect investors who purchase in this offering. Stabilizing transactions consist of various bids for or purchases of our common units made by the underwriters in the open market prior to the completion of this offering.

The underwriters may also impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the underwriters have repurchased common units sold by or for the account of such underwriter in stabilizing or short covering transactions.

Similar to other purchase transactions, the underwriters' purchases to cover the syndicate short sales may have the effect of raising or maintaining the market price of our common units or preventing or retarding a decline in the market price of our common units. As a result, the price of our common units may be higher than the price that might otherwise exist in the open market. The underwriters may conduct these transactions on the NYSE, in the over-the-counter market or otherwise.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of our common units. In addition, neither we nor any of the underwriters make any representation that the underwriters will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

Electronic Distribution

In connection with this offering, certain of the underwriters or securities dealers may distribute prospectuses by electronic means, such as e-mail. In addition, the underwriters may facilitate Internet distribution for this offering to certain of their Internet subscription customers. The underwriters may allocate a limited number of our common units for sale to their online brokerage customers. An electronic prospectus may be available on the websites maintained by the underwriters. Other than the prospectus in electronic format, the information on the underwriters' websites is not part of this prospectus.

Other Relationships

In addition, in the ordinary course of their business activities, the underwriters and their affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers. Such investments and securities activities may involve securities and/or instruments of ours or our affiliates. The underwriters and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

Direct Participation Program Requirements

Because FINRA views the common units offered hereby as interests in a direct participation program, the offering is being made in compliance with FINRA Rule 2310. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

VALIDITY OF THE COMMON UNITS

The validity of the common units and certain tax matters will be passed upon for us by Latham & Watkins LLP, Austin, Texas. Certain legal matters in connection with the common units offered by us will be passed upon for the underwriters by Baker Botts L.L.P., Houston, Texas.

EXPERTS

The audited consolidated financial statements of MorningStar Partners, L.P. as of and for the year ended December 31, 2020 and 2021 included in this prospectus and elsewhere in the registration statement have been so included in reliance upon the reports of KPMG LLP, independent registered public accounting firm, appearing elsewhere herein, upon the authority of said firm as experts in auditing and accounting.

Estimated quantities of proved oil and natural gas reserves of MorningStar Partners, L.P. and the net present value of such reserves as of January 1, 2022 set forth in this prospectus are based upon reserve reports prepared by our internal reservoir engineers and evaluated by Cawley, Gillespie & Associates.

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WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-l (including the exhibits, schedules and amendments thereto) regarding our common units. This prospectus, which constitutes part of the registration statement, does not contain all of the information set forth in the registration statement and the exhibits and schedules thereto. For further information regarding us and our common units offered in this prospectus, we refer you to the full registration statement, including its exhibits and schedules, filed under the Securities Act. Statements contained in this prospectus as to the contents of any contract, agreement or any other document are summaries of the material terms of such contract, agreement or other document and are not necessarily complete. With respect to each of these contracts, agreements or other documents filed as an exhibit to the registration statement, reference is made to the exhibits for a more complete description of the matter involved. The SEC maintains a website that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC. Our registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC's website. The address of the SEC's website is www.sec.gov.

As a result of the offering, we will become subject to full information requirements of the Securities Exchange Act of 1934. We intend to furnish or make available to our unitholders annual reports containing our audited financial statements and furnish or make available quarterly reports containing our unaudited interim financial information, including the information required by Form 10-Q, for the first three fiscal quarters of each of our fiscal years. Additionally, we intend to file other periodic reports with the SEC, as required by the Securities Exchange Act of 1934.

FORWARD-LOOKING STATEMENTS

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

- business strategies;
- the impact of recent acquisitions and our ability to integrate acquired properties and manage related growth;
- our 2022 capital budget;
- ability to replace the reserves we produce through acquisitions and the development of our properties;
- our oil and natural gas reserves;
- general economic conditions, including the effects of a global health crises such as the COVID-19 pandemic;
- realized oil, natural gas and NGL prices, including the impact of actions relating to oil price and production controls by OPEC, its members and other state-controlled companies;
- the timing and amount of future production of oil, natural gas and NGL;
- our hedging strategy and results;
- our future drilling plans and locations;
- costs of developing our properties, including our projected drilling and completion costs;
- costs associated with managing our business, including anticipated production expense and G&A expense;
- future operating results;
- cash flow and liquidity;
- availability of production equipment and oil field labor;
- capital expenditures;
- availability and terms of capital;

- tax treatment;
- marketing, transportation and storage of oil, natural gas and NGL;
- competition in the oil and natural gas industry;
- effectiveness of risk management activities;
- environmental liabilities;
- governmental regulation and taxation;
- developments in oil producing and natural gas producing countries; and
- plans, objectives, expectations and intentions.

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

- commodity price volatility;
- the impact of epidemics, outbreaks or other public health events, and the related effects on financial markets, worldwide economic activity and our operations;
- the impact of COVID-19, and governmental measures related thereto, on global demand for oil and natural gas and on the operations of our business;
- uncertainties about our estimated oil, natural gas and NGL reserves, including the impact of commodity price declines on the economic producibility of such reserves, and in projecting future rates of production;
- the concentration of our operations in the Permian Basin and the San Juan Basin;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- lack of transportation and storage capacity as a result of oversupply, government regulations or other factors;
- lack of availability of drilling and production equipment and services;
- potential financial losses or earnings reductions resulting from our commodity price risk management program or any inability to manage our commodity risks;
- failure to realize expected value creation from property acquisitions and trades;
- access to capital and the timing of development expenditures;

- environmental, weather, drilling and other operating risks;
- regulatory changes, including potential shut-ins or production curtailments mandated by the Railroad Commission of Texas;
- competition in the oil and natural gas industry;
- loss of production and leasehold rights due to mechanical failure or depletion of wells and our inability to re-establish their production;
- our ability to service our indebtedness;
- any downgrades in our credit ratings that could negatively impact our cost of and ability to access capital;
- cost inflation;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, the armed conflict in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;
- evolving cybersecurity risks such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insider or other with authorized access, cyber or phishing-attacks, ransomware, social engineering, physical breaches or other actions; and
- risks related to our ability to expand our business, including through the recruitment and retention of qualified personnel.

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

Should one or more of the risks or uncertainties described in this prospectus occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this prospectus are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

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

INDEX TO FINANCIAL STATEMENTS

TXO ENERGY PARTNERS, L.P.
PRO FORMA FINANCIAL STATEMENTS
(Unaudited)

Introduction

TXO Energy Partners, L.P. (the "Company") is the new name of MorningStar Partners, L.P. ("MorningStar") to engage 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 the Company reflect the historical results of MorningStar, 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 March 31, 2022, for pro forma balance sheet purposes, and on January 1, 2021, for pro forma income statement purposes:

- in the case of the unaudited pro forma statements of operations, the acquisition of the Vacuum properties as described in Note 2 to the historical audited financial statements of MorningStar included elsewhere in this prospectus;

- the initial public offering of common units and the use of the net proceeds therefrom as described in "Use of Proceeds" (the "Offering"). For purposes of the unaudited pro forma financial statements, the Offering is defined as the planned issuance and sale to the public of common units of the Company as contemplated by this prospectus and the application by the Company of the net proceeds from such issuance as described in "Use of Proceeds." The net proceeds from the sale of the common stock are expected to be $, net of underwriting discounts of $ and other offering costs of $; and

The unaudited pro forma balance sheet of the Company is based on the historical balance sheet of MorningStar as of March 31, 2022 and includes pro forma adjustments to give effect to the described transactions as if they had occurred on March 31, 2022. The unaudited pro forma statements of operations of the Company are based on the audited historical statement of operations of MorningStar for the year ended December 31, 2021, and the unaudited historical statement of operations of MorningStar for the three months ended March 31, 2022, both having been adjusted to give effect to the described transactions as if they occurred on January 1, 2021.

The pro forma data presented reflect events directly attributable to the described transactions and certain assumptions the Company 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 public 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 as contemplated 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 Offering and other transactions contemplated herein had occurred in the past, the Company's 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 the Company would have achieved if the Offering and other transactions contemplated 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 the Company will have after the contemplation of the offering and the other transactions contemplated by these unaudited pro forma financial statements.

TXO ENERGY PARTNERS, L.P.
PRO FORMA BALANCE SHEET
March 31, 2022

(in thousands)

	MorningStar Partners, L.P. Historical	Offering	Pro Forma
ASSETS			
Current Assets:			
Cash and cash equivalents	$ 15,356	$	$
Accounts receivable, net	48,862		
Derivative fair value	1,651		
Other	6,121		
Total Current Assets	71,990		
Property and Equipment, at cost—successful efforts method:			
Proved properties	1,380,916		
Unproved properties	18,715		
Other	70,559		
Total Property and Equipment	1,470,190		
Accumulated depreciation, depletion and amortization	(713,860)		
Net Property and Equipment	756,330		
Other Assets:			
Note receivable from related party	7,130		
Derivative fair value	2,200		
Other	2,983		
Total Other Assets	12,313		
TOTAL ASSETS	$ 840,633	$	$
LIABILITIES AND PARTNERS' CAPITAL			
Current Liabilities:			
Accounts payable	$ 8,934	$	$
Accrued liabilities	25,925		
Derivative fair value	61,483		
Asset retirement obligation, current portion	1,100		
Total Current Liabilities	97,442		
Long-term Debt	137,100(a)		
Other Liabilities:			
Asset retirement obligation	104,924		
Derivative fair value	24,744		
Other liabilities	647		
Total Other Liabilities	130,315		
Commitments and Contingencies			
Partners' Capital:			
Partners' capital	475,776		
Common stock	—(a)		
Additional paid in capital	—(a)		
Total Shareholders' Equity	475,776		
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 840,633	$	$

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

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TXO ENERGY PARTNERS, L.P.
Pro Forma Statements of Operations for the Year Ended December 31, 2021
(Unaudited)

(in thousands, except for per share information)

	MorningStar Partners, L.P. Historical	Vacuum Properties	Offering	Pro Forma
		(b)		
REVENUES				
Oil and condensate	$ 69,971	$ 48,215	$ —	$
Natural gas liquids	27,875	1,935	—	
Gas	130,498	178	—	
Total Revenues	228,344	50,328	—	
EXPENSES				
Production	69,256	30,150		
Exploration	124	—		
Taxes, transportation and other	58,040	5,062		
Depreciation, depletion, and amortization	39,889(c)	7,761		
Accretion of discount in asset retirement obligation	4,670(d)	292		
General and administrative	12,175	—		
Total Expenses	184,154	43,265		
OPERATING INCOME (LOSS)	44,190	7,063		
OTHER INCOME (EXPENSE)				
Other income	14,139	3,173		
Interest income	16	—		
Interest expense	(5,870)(e)	(1,328)		
Other Income	8,285	1,845		
NET INCOME (LOSS)	$ 52,475	$ 8,908	$	$
NET INCOME (LOSS) PER COMMON SHARE(f)				
Basic	$	$	$	$
Diluted	$	$	$	$
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING(f)				
Basic	$	$	$	$
Diluted	$	$	$	$

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

TXO ENERGY PARTNERS, L.P.
Pro Forma Statements of Operations for the Three Months Ended March 31, 2022
(Unaudited)

(in thousands, except for per share information)

	MorningStar Partners, L.P. Historical	Offering	Pro Forma
REVENUES			
Oil and condensate	$ (2,530)	$	$
Natural gas liquids	3,121		
Gas	(10,129)		
Total Revenues	(9,538)		
EXPENSES			
Production	25,026		
Exploration	87		
Taxes, transportation and other	23,487		
Depreciation, depletion, and amortization	9,780		
Accretion of discount in asset retirement obligation	1,477		
General and administrative	396		
Total Expenses	60,253		
OPERATING LOSS	(69,791)		
OTHER INCOME (EXPENSE)			
Other income	5,872		
Interest income	6		
Interest expense	(1,670)		
Other Income	4,208		
NET INCOME (LOSS)	$ (65,583)		
NET INCOME (LOSS) PER COMMON SHARE(f)			
Basic	$		
Diluted	$		
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING(f)			
Basic	$		
Diluted	$		

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

TXO ENERGY, LLC
Notes to Pro Forma Financial Statements

1. BASIS OF PRESENTAION, THE OFFERING AND REORGANIZATION

The historical financial information is derived from the financial statements of MorningStar included elsewhere in this prospectus. For purposes of the unaudited pro forma balance sheet, it is assumed that the transactions had taken place on March 31, 2022. For purposes of the unaudited pro forma statements of operations, it is assumed all transactions had taken place on January 1, 2021.

Upon closing the Offering, the Company expects to incur direct, incremental general and administrative expenses as a result of being publicly traded, including, but not limited to, costs associated with annual and quarterly reports to stockholders, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and independent director compensation. The Company estimates these direct, incremental general and administrative expenses initially will total approximately $ million per year. These direct, incremental general and administrative expenditures are not reflected in the historical financial statements or in the unaudited pro forma financial statements.

Prior to the offering MorningStar Partners, L.P. will be renamed TXO Energy Partners, L.P. ("TXO Energy") in connection with the reorganization transactions as described herein. Following this offering and the corporate reorganization described below, TXO Energy will be a holding company, whose sole material assets will consist of a partnership interest in MorningStar Partners, L.P. MorningStar owns, directly or indirectly, all of our operating assets. After the consummation of the corporate reorganization, TXO Energy. will indirectly own the sole general partner of MorningStar Partners, L.P., will be responsible for all operational, management and administrative decisions relating to MorningStar Partners, L.P.'s business and will consolidate the financial results of MorningStar Partners, L.P. and its subsidiaries and joint venture.

2. PRO FORMA ADJUSTMENTS AND ASSUMPTIONS

The Company made the following adjustments and assumptions in the preparation of the unaudited pro forma financial statements:

(a) Reflects estimated gross proceeds of $ million from the issuance and sale of common units at an assumed initial public offering price of $ per share, net of underwriting discounts and commissions of $ million, in the aggregate, and additional estimated expenses related to the Offering of approximately $ million and the use of the net proceeds therefrom as follows:

- Repay outstanding borrowings under the Credit Facility, which were $130 million as of March 31, 2022;
- Repay outstanding borrowings under the MorningStar Partners loan with Cross Timbers Energy, which were $7.1 million as of March 31, 2022; and
- Working capital and general partnership purposes.

(b) Unless otherwise noted below in items (c) - (e), adjustments reflect the historical statements of revenues and direct operating expenses from the assets acquired and liabilities assumed in the acquisition of the Vacuum Properties, as included elsewhere in this prospectus.

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(c) Adjustment reflects additional depreciation, depletion, and amortization expense that would have been incurred with respect to the acquisition of the Vacuum Properties, had such acquisitions occurred on January 1, 2021.

(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 acquisition of the Vacuum Properties, had such acquisition occurred on January 1, 2021.

(e) Adjustment reflects additional interest expense that would have been incurred in connection with the borrowing to fund the acquisition of the Vacuum Properties, had such acquisition occurred on January 1, 2021.

(f) Reflects basic and diluted earnings (loss) per common share for the issuance of shares of common stock in the Corporate Reorganization and the Offering as shown below:

	Year ended December 31, 2021	Three months ended March 31, 2021
Basic		
Net income (loss)		
Shares issued in the Corporate Reorganization and The Offering		
Basic earnings (loss) per share		
Diluted		
Numerator:		
Net income (loss)		
Effect of dilutive securities		(a)
Diluted net income (loss) attributable to stockholders		
Denominator:		
Basic weighted average shares outstanding		
Effect of dilutive securities		(a)
Diluted weighted average shares outstanding		
Diluted earnings (loss) per share		

(a) – As there was a net loss for the period, any incremental shares would be anti-dilutive. As such, the potentially diluted shares totaling 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 Energy's proved reserves reflect the effect of Texas state franchise taxes which partnerships are 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 Energy's 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, 2021, 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, 2021.

Oil (MBbls)	MorningStar Partners, L.P. Historical	Vacuum Properties	Pro Forma
January 1, 2021	19,604.8	19,042.3	38,647.1
Extensions, additions and discoveries	—	—	—
Revisions	2,762.3	2,548.5	5,310.8
Production	(1,033.0)	(746.4)	(1,779.4)
Purchase in place	27,236.7	(20,844.4)	6,392.3
December 31, 2021	48,570.8	—	48,570.8
Proved Developed Reserves			
January 1, 2021	9,787.7	12,426.6	22,214.3
December 31, 2021	30,207.9	—	30,207.9
Proved Undeveloped Reserves			
January 1, 2021	9,817.1	6,615.7	16,432.8
December 31, 2021	18,362.9	—	18,362.9

Natural Gas Liquids (MBbls)	MorningStar Partners, L.P. Historical	Vacuum Properties	Pro Forma
January 1, 2021	8,311.2	3,302.4	11,613.6
Extensions, additions and discoveries	0.1	—	0.1
Revisions	7,288.3	193.1	7,481.4
Production	(1,088.8)	(48.5)	(1,137.3)
Purchase in place	3,513.6	(3,447.0)	66.6
December 31, 2021	18,024.4	—	18,024.4
Proved Developed Reserves			
January 1, 2021	8,311.2	2,737.8	11,049.0
December 31, 2021	17,434.2	—	17,434.2
Proved Undeveloped Reserves			
January 1, 2021	—	564.6	564.6
December 31, 2021	590.2	—	590.2

Natural Gas (MMcf)	MorningStar Partners, L.P. Historical	Vacuum Properties	Pro Forma
January 1, 2021	243,172.9	2,316.9	245,489.8
Extensions, additions and discoveries	5,644.9	—	5,644.9
Revisions	153,290.1	294.2	153,584.3
Production	(30,589.7)	(84.2)	(30,673.9)
Purchase in place	7,757.6	(2,526.9)	5,230.7
December 31, 2021	379,275.8	—	379,275.8
Proved Developed Reserves			
January 1, 2021	218,396.9	1,950.2	220,347.1
December 31, 2021	353,214.8	—	353,214.8
Proved Undeveloped Reserves			
January 1, 2021	24,776.0	366.7	25,142.7
December 31, 2021	26,061.0	—	26,061.0

Total (MBoe)	MorningStar Partners, L.P. Historical	Vacuum Properties	Pro Forma
January 1, 2021	68,444.8	22,730.9	91,175.7
Extensions, additions and discoveries	940.9	—	940.9
Revisions	35,599.0	2,790.6	38,389.6
Production	(7,220.1)	(808.9)	(8,029.0)
Purchase in place	32,043.3	(24,712.6)	7,330.7
December 31, 2021	129,807.9	—	129,807.9
Proved Developed Reserves			
January 1, 2021	54,498.4	15,489.5	69,987.9
December 31, 2021	106,511.3	—	106,511.3
Proved Undeveloped Reserves			
January 1, 2021	13,946.4	7,241.4	21,187.8
December 31, 2021	23,296.6	—	23,296.6

The pro forma standardized measure of discounted estimated future net cash flows was as follows as of December 31, 2021 (in thousands):

	MorningStar Partners, L.P. Historical	Pro Forma
(in thousands)		
Future cash inflows	$ 4,468,597	
Future costs:		
Production	(1,988,988)	
Development	(365,289)	
Income taxes	(4,110)	
Future net cash flows	2,110,210	
10% annual discount	(1,123,593)	
Standardized measure	$ 986,617	$

The change in the pro forma standardized measure of discounted estimated future net cash flows were as follows for 2021 (in thousands):

	MorningStar Partners, L.P. Historical	Vacuum Properties	Pro Forma
(in thousands)			
Standardized measure, beginning of period	$ 154,438	$ 109,720	$
Revisions:			
Prices and costs	205,842	136,525	
Quantity estimates	76,737	35,757	
Income tax	(1,933)	—	
Future development costs	2,715	—	
Accretion of discount	15,444	10,972	
Production rates and other	42,064	2,754	
Net revisions	340,869	186,008	
Additions and discoveries	20,272	—	
Production	(93,042)	(18,289)	
Development costs	13,973	—	
Purchases in place	550,107	(277,439)	
Net change	832,179	(109,720)	
Standardized measure, end of period	$ 986,617	$ —	$

MORNINGSTAR PARTNERS, L.P.

Consolidated Financial Statements

December 31, 2021 and 2020

Report of Independent Registered Public Accounting Firm

To the Partners
MorningStar Partners, L.P.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of MorningStar Partners, L.P. and subsidiaries (the Company) as of December 31, 2021 and 2020, the related consolidated statements of operations, partners' capital, and cash flows for years then ended, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the relevant ethical requirements relating to our audits.

We conducted our audits in accordance with the auditing standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

(signed) KPMG LLP

We have served as the Company's auditor since 2012

Dallas, Texas
July 13, 2022

MORNINGSTAR PARTNERS, L.P.
Consolidated Balance Sheets

(in thousands)

	December 31, 2021	December 31, 2020
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 7,547	$ 21,933
Accounts receivable, net	34,124	16,122
Derivative fair value	10,632	—
Other	4,793	3,223
Total Current Assets	57,096	41,278
Property and Equipment, at cost—successful efforts method:		
Proved properties	1,376,476	1,183,202
Unproved properties	18,677	18,609
Other	69,254	37,983
Total Property and Equipment	1,464,407	1,239,794
Accumulated depreciation, depletion and amortization	(704,080)	(666,005)
Net Property and Equipment	760,327	573,789
Other Assets:		
Note receivable from related party	7,132	7,131
Derivative fair value	4,912	—
Other	3,353	1,742
Total Other Assets	15,397	8,873
TOTAL ASSETS	$ 832,820	$ 623,940
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities:		
Accounts payable	$ 3,965	$ 3,660
Accrued liabilities	23,758	14,157
Derivative fair value	6,450	—
Asset retirement obligation, current portion	1,100	1,100
Total Current Liabilities	35,273	18,917
Long-term Debt	152,100	151,252
Other Liabilities:		
Asset retirement obligation	103,389	99,570
Derivative fair value	117	—
Other liabilities	582	238
Total Other Liabilities	104,088	99,808
Commitments and Contingencies		
Mandatorily redeemable convertible preferred units	—	50,695
Partners' Capital:		
Partners' capital	541,359	303,268
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 832,820	$ 623,940

See accompanying notes to consolidated financial statements.

MORNINGSTAR PARTNERS, L.P.
Consolidated Statements of Operations

(in thousands)

	Years ended December 31, 2021	2020
REVENUES		
Oil and condensate	$ 69,971	$ 59,070
Natural gas liquids	27,875	8,660
Gas	130,498	41,034
Total Revenues	228,344	108,764
EXPENSES		
Production	69,256	49,146
Exploration	124	55
Taxes, transportation and other	58,040	27,509
Depreciation, depletion, and amortization	39,889	42,322
Impairment	—	134,097
Accretion of discount in asset retirement obligation	4,670	3,940
General and administrative	12,175	6,995
Total Expenses	184,154	264,064
OPERATING INCOME (LOSS)	44,190	(155,300)
OTHER INCOME (EXPENSE)		
Other income	14,139	72
Interest income	16	194
Interest expense	(5,870)	(8,204)
Other Income (Expense)	8,285	(7,938)
NET INCOME (LOSS)	$ 52,475	$ (163,238)
PRO FORMA INFORMATION (UNAUDITED):		
Unaudited supplemental pro forma net income per common share (Note 1)		
Basic		
Diluted		
Unaudited supplemental pro forma weighted average shares outstanding (Note 1)		
Basic		
Diluted		

See accompanying notes to consolidated financial statements.

MORNINGSTAR PARTNERS, L.P.
Consolidated Statements of Cash Flows

(in thousands)

	Years ended December 31, 2021	2020
OPERATING ACTIVITIES		
Net income (loss)	$ 52,475	$ (163,238)
Adjustments to reconcile net income (loss) to net cash provided by operating activities, net of effects of assets acquired and liabilities assumed:		
Depreciation, depletion, and amortization	39,889	42,322
Impairment	—	134,097
Accretion of discount in asset retirement obligation	4,670	3,940
Derivative fair value (gain) loss	(8,977)	(23,305)
Net cash received from (paid to) counterparties	—	26,192
Non-cash gain on forgiveness of debt	(9,152)	—
Non-cash incentive compensation	2,400	4,227
Other non-cash items	(585)	886
Changes in operating assets and liabilities *(a)*	(6,994)	(6,157)
Cash Provided by Operating Activities	73,726	18,964
INVESTING ACTIVITIES		
Proved property acquisitions	(185,931)	(10,961)
Development costs	(8,372)	(4,989)
Unproved property acquisitions	(67)	(307)
Other property additions	(33,431)	(461)
Cash Used in Investing Activities	(227,801)	(16,718)
FINANCING ACTIVITIES		
Proceeds from long-term debt	1,437,000	1,932,152
Payments on long-term debt	(1,427,000)	(1,968,000)
Proceeds from temporary equity investment	—	50,695
Proceeds from permanent equity investment	132,660	—
Debt issuance costs	(2,832)	(709)
Payments on vesting of restricted units	—	(40)
Distributions	(139)	(31)
Cash Provided by Financing Activities	139,689	14,067
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(14,386)	16,313
Cash and Cash Equivalents, beginning of period	21,933	5,620
Cash and Cash Equivalents, end of period	$ 7,547	$ 21,933
(a) **Changes in Operating Assets and Liabilities**		
Accounts receivable	$ (14,811)	$ (8,103)
Other assets	(1,571)	(240)
Aid-in-construction asset	—	(238)
Current liabilities	10,028	3,224
Other operating liabilities	(640)	(800)
	$ (6,994)	$ (6,157)

See accompanying notes to consolidated financial statements.

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MORNINGSTAR PARTNERS, L.P.
Consolidated Statements of Partners' Capital

(in thousands)

	Series 3 Preferred	Series 4 Preferred	Series 5 Preferred	Common	Total
Balances, December 31, 2019	$ 34,295	$ —	$ —	$ 428,055	$ 462,350
Net loss	—	—	—	(163,238)	(163,238)
Increase in partners' equity fromin-kind distributions	—	—	—	1,585	1,585
In-kind distributions	—	—	—	(1,585)	(1,585)
Expensing of unit awards	—	—	—	4,227	4,227
Withholding tax paid on vesting restricted units	—	—	—	(40)	(40)
Distributions	—	—	—	(31)	(31)
Balances, December 31, 2020	$ 34,295	$ —	$ —	$ 268,973	$ 303,268
Net income	—	—	—	52,475	52,475
Increase in partners' equity fromin-kind distributions	—	—	—	8,248	8,248
In-kind distributions	—	—	—	(8,248)	(8,248)
Expensing of unit awards	—	—	—	2,400	2,400
Contributions of cash	—	—	132,660	—	132,660
Distributions	—	—	—	(139)	(139)
Accretion of original issue discount on temporary equity	—	(2,668)	—	—	(2,668)
Conversion of temporary equity to permanent equity	—	53,363	—	—	53,363
Gain (loss) from the exchange of Series 4 preferred units	—	22,719	—	(22,719)	—
Exchange of Series 4 preferred units to Series 5 preferred units	—	(73,414)	73,414	—	—
Balances, December 31, 2021	$ 34,295	$ —	$206,074	$ 300,990	$ 541,359

See accompanying notes to consolidated financial statements.

MORNINGSTAR PARTNERS, L.P.
Notes to Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

MorningStar Partners, L.P. (MorningStar or the Company), is an independent oil and gas company that was formed as a Delaware limited partnership in January 2012 (with an effective inception of operations at January 18, 2012). The operations of MorningStar are governed by the provisions of the partnership agreement, as amended, executed by the general partner, MorningStar Oil & Gas, LLC (MSOG) and the limited partners. MSOG is the manager of MorningStar and is paid a quarterly management fee equal to 1% of revenue, less production expense, severance taxes and other deductions, at the discretion of the MorningStar board of directors. Under the amended partnership agreement, this management fee is currently suspended. MorningStar is governed by a board of directors made up of five officers and five outside investors. The agreement includes specific provisions with respect to the maintenance of the capital accounts of each of the Company's partners. Pursuant to applicable provisions of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act") and the limited partnership agreement, the partners have no liability for the debts, obligations and liabilities of MorningStar, except as expressly required in the limited partnership agreement or the Delaware Act. MorningStar will remain in existence unless and until dissolved in accordance with the terms of the partnership agreement.

MorningStar's assets include its investment in an unincorporated joint venture. MorningStar owns 50% of the joint venture, and MorningStar is the manager of the joint venture. The joint venture is governed by a Member Management Committee (MMC) and is comprised of six representatives, three from each group, with each group having one voting member. All matters that come before the MMC require the unanimous consent of the voting members. On the last day of each calendar quarter, the joint venture distributes all excess cash to the members based on their ownership percentage of 50% each, except for earnings from the note receivable which is owned 5% by MorningStar. The joint venture's properties are located primarily in the Permian Basin of West Texas and New Mexico and the San Juan Basin of New Mexico and Colorado.

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

In accordance with oil and gas accounting guidance, we account for our undivided interest in our investment in the joint venture using the proportionate consolidation method. Under this method, we consolidate our proportionate share of assets, liabilities, revenues and expenses of the joint venture. As discussed above, we own 50% of the oil and gas assets, liabilities, revenues and expenses, but we only own 5% of the note receivable from related party and related interest income.

In February 2015, we entered into a Limited Liability Company Agreement, as amended, (LLC Agreement) with EnCap Energy Capital Fund IX, L.P. and EnCap Energy Capital Fund X, L.P. (EnCap entities) to form Southland Royalty Company LLC (Southland LLC). On January 27, 2020, Southland filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware (January 2020 Reorganization Filing). As a result, we deconsolidated our remaining investment in Southland as of December 31, 2019. However, we remained involved with the management and wind down of Southland until Southland exited from bankruptcy in June 2021.

The accompanying consolidated financial statements include the financial statements of MorningStar, its wholly-owned subsidiaries and our undivided interests in the joint venture. All significant intercompany balances and transactions have been eliminated in consolidation.

Basis of Presentation

The accounts of MorningStar are presented in the accompanying financial statements. These financial statements have been prepared in accordance with U.S. GAAP. The statement of operations includes unaudited supplemental pro forma information which gives effect to basic and diluted pro forma income per common unit for the year ended December 31, 2021

Liquidity

Our primary sources of liquidity are cash provided by operating activities, borrowings under our credit facility and equity raised from partners. 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 4.

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;
- estimates of revenue earned but not yet received;
- asset retirement obligations; and
- legal and environmental risks and exposure.

Property and Equipment

We follow the successful efforts method of accounting, capitalizing costs of successful exploratory wells and expensing costs of unsuccessful exploratory wells. Exploratory geological and geophysical costs are expensed as incurred. All developmental costs are capitalized. We generally pursue acquisition and development of proved reserves as opposed to exploration activities. All of the proved property costs reflected in the accompanying balance sheet are from MorningStar, our wholly-owned subsidiary, MorningStar Operating, LLC, and our 50% share of the joint venture’s proved properties as of December 31, 2021 and 2020. Proved properties balances include costs of $2.4 million at December 31, 2021 and $5.9 million at December 31, 2020 related to wells in process of drilling. Successful drill well costs are transferred to proved properties generally within one month of the well completion date.

Depreciation, depletion, and amortization (DD&A) of proved producing properties is computed on the unit-of-production method based on estimated proved oil and gas reserves. Other property and equipment is generally depreciated using the straight-line method over estimated useful lives which range from three to seven years, except for the gas processing plant which is being depreciated over an estimated useful life of 14 years. Repairs and maintenance are expensed, while renewals and betterments are generally capitalized.

If conditions indicate that proved properties may be impaired, the carrying value of property is compared to management's future estimated pre-tax undiscounted cash flow from properties generally aggregated on a field-level basis. If impairment is necessary, the asset carrying value is written down to fair value, typically a discounted present value of estimated future cash flows. Cash flow pricing estimates are based on estimated reserves and production information and pricing assumptions that management believes are reasonable. During the year end ended December 31, 2021, we did not recognize an impairment of long-lived assets. During the year end ended December 31, 2020, we recognized an impairment of long-lived assets of $133.2 million for our assets in the New Mexico Permian Basin, $0.2 million for our assets in East Texas and $0.7 million on our unproved properties primarily in the Texas Permian Basin primarily due to a lower net commodity price environment for some of our oil and natural gas assets.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion, and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized in the current period.

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 statement of operations. See Note 8.

Cash and Cash Equivalents

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

MorningStar is a limited partnership treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas franchise tax on gross revenue, with income tax liabilities and/or benefits of the Company passed through to the partners. As such, with the exception of the state of Texas, we are not a taxable entity, we do not directly pay federal and state income tax and recognition has not been given to federal and state income taxes for our operations, except as described below.

Limited partnerships are subject to state franchise taxes on gross revenue in Texas. Due to immateriality, franchise taxes related to the Texas margin tax have been included in general and administrative expenses on the statement of operations and no deferred tax amounts were calculated.

Derivatives

We use derivatives to hedge against changes in cash flows related to product price, as opposed to their use for trading purposes. We record 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 (Note 10).

We do not designate these derivative contracts as cash flow hedges. Changes in the fair value of commodity price derivatives are recognized currently in earnings. Realized and unrealized gains and losses on commodity derivatives are recognized in oil and gas revenues. Settlements of derivatives are included in cash flows from operating 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 Company expects to be entitled in exchange for the product. See Note 13 for further discussion.

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.

Unit-Based Compensation

We recognize compensation related to all unit-based awards in the financial statements based on their estimated grant-date fair value. We estimate expected forfeitures and we recognize compensation expense only for those awards expected to vest. Compensation expense is amortized on a straight-line basis over the estimated service period. All compensation is recognized by the time the award vests. See Note 12.

Significant Purchasers

We evaluated how MorningStar is organized and managed and have identified only one operating segment, which is the exploration and production of oil, natural gas and natural gas liquids. All of our assets are located in the United States, and all revenues are attributable to United States customers.

Our production is sold to various purchasers, based on their credit rating and the location of our production. Sales to three purchasers for the year ended December 31, 2021 and sales to two purchasers for the year ended December 31, 2020, as shown in the table below, 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	2021	2020
Customer A	19%	25%
Customer B	12%	17%
Customer C	11%	—%

2. Establishment of Joint Ventures and Acquisitions

Joint Venture

On October 1, 2012, our joint venture partner contributed producing properties with a fair value of $805.2 million and MorningStar contributed cash of $425.7 million to the joint venture. In a second transaction, our joint venture partner contributed additional producing properties with a fair value of $48.0 million and MorningStar contributed additional cash of $25.3 million. The contributed cash, less $4.0 million retained for working capital purposes, was loaned to an offshore subsidiary of our joint venture partner. See Note 5.

Since that time, MorningStar has contributed $467.5 million of cash and $107.0 million of proved properties, while our joint venture partner has contributed $663.6 million of proved property.

Acquisitions

In February 2022, MorningStar completed the acquisition of producing properties in the Permian Basin of Texas from Kaiser Francis for approximately $3.8 million. Our purchase price allocation included $4.0 million to proved properties and $0.2 million to asset retirement obligation. The acquisition was funded by cash on hand.

In December 2021, MorningStar completed the acquisition of producing properties in the Permian Basin of Texas from Chevron for approximately $43.8 million. Our purchase price allocation included $47.2 million to proved properties and $3.4 million to asset retirement obligation. The acquisition was funded by cash on hand and borrowings from our credit facility. The acquisition is subject to typical post-closing adjustments.

In November 2021, MorningStar completed the acquisition of producing properties and a gas processing plant in the Permian Basin of New Mexico and CO^2 assets in Colorado from Chevron for approximately $175.4 million. Our purchase price allocation included $145.2 million to proved properties, $33.3 million to other properties, $4.3 million to other current assets and $7.4 million to asset retirement obligation. The acquisition was funded by cash on hand from the October 2021 capital raise (see Note 11) and borrowings from our credit facility. The acquisition is subject to typical post-closing adjustments. In the 2021 statement of operations, we recorded $15.0 million of revenues and income of $2.8 million from this acquisition.

In June 2020, MorningStar completed the acquisition of producing properties in the San Juan Basin of New Mexico and Colorado from Southland Royalty for approximately $10.2 million. Our purchase price allocation included $69.0 million to proved properties, $54.6 million to asset retirement obligation, $4.0 million to other current liabilities and $0.2 million to other liabilities. The acquisition was funded by cash on hand.

During 2020, we completed multiple acquisitions of producing properties in the Permian Basin of Texas and New Mexico for $0.7 million. We allocated $ $0.7 million to proved property. These were funded by cash on hand.

Pro forma financial information

The following pro forma financial information represents the results for the Company and the properties acquired in November 2021 in the Permian Basin of New Mexico and CO_2 assets in Colorado from Chevron as if the acquisition and the required financing had occurred on January 1, 2020.

For the pro forma year ended December 31, 2021, pro forma revenues were $278.7 million and pro forma net income was $61.4 million. For the purposes of the pro forma, it was assumed that $40.0 million of the Company's revolving credit facility was used to finance the acquisition resulting in additional interest expense of $1.3 million. The pro forma financial information includes the effects of adjustments for depreciation, depletion, and amortization of $7.8 million, and accretion of asset retirement obligations expense of $0.3 million.

For the pro forma year ended December 31, 2020, pro forma revenues were $149.2 million and pro forma net loss was $159.0 million. For the purposes of the pro forma, it was assumed that $40.0 million of the Company's revolving credit facility was used to finance the acquisition resulting in additional interest expense of $1.6 million. The pro forma financial information includes the effects of adjustments for depreciation, depletion, and amortization of $11.0 million, and accretion of asset retirement obligations expense of $0.4 million.

The pro forma results do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by the Company to integrate the properties acquired. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisition had been completed as of the beginning of the period, nor are they necessarily indicative of future results.

3. Related Party Transactions

We earned management fees from the joint venture of $6.1 million for the year ended December 31, 2021, and $6.4 million for the year ended December 31, 2020. As of December 31, 2021, we had a note receivable from related party outstanding with a highly-rated, offshore subsidiary of our joint venture partner (Note 5). On September 30, 2016, MorningStar entered in a loan agreement with the joint venture (Note 4).

We earned management fees from Southland Royalty Company of $5.0 million for the year ended December 31, 2021 and $15.5 million for the year ended December 31, 2020.

Since the purpose of the management fees is to share costs between the various entities, the management fees from the joint venture and Southland are included as a reduction of general and administrative expenses in our statements of operations.

We occupy a building owned by MorningStar Capital LLC, a limited liability company owned by one of our limited partners. In lieu of paying rent, we paid property taxes and paid for repairs and maintenance on behalf of MorningStar Capital of $0.9 million in 2021 and $1.5 million in 2020.

We did not pay management fees to our general partner, MSOG, in 2021 and 2020.

4. Debt

(in thousands)	December 31, 2021	December 31, 2020
MorningStar Partners Credit Facility, 3.6% at December 31, 2020	$ —	$ 137,000
November 2021MorningStar Partners Credit Facility, at 4.0% at December 31, 2021	$ 145,000	$ —
MorningStar Partners Loan, 3.4% at December 31, 2021 and 3.4% at December 31, 2020	$ 7,100	$ 7,100
MorningStar Partners Paycheck Protection Program Loan, 1.0% at December 31, 2020	$ —	$ 7,152
Total Long-term Debt	$ 152,100	$ 151,252

MorningStar Partners Credit Facility

On October 1, 2012, we entered into a five-year, $350 million senior secured credit facility with certain commercial banks. The facility had a maturity date of October 1, 2022. On July 1, 2013, we entered into an amendment to the senior secured credit facility to increase the commitment to $750 million. The amended facility was limited to the lesser of: (i) the then effective borrowing base or (ii) the maximum commitment amount. We had the option, with bank approval, to increase the commitment up to $1 billion. On April 29, 2020, we entered into the thirteenth amendment to the agreement and redetermined the borrowing base to $115 million. As a result of the redetermination, there was a borrowing base deficiency of $65 million. A payment of at least $35 million was due no later than June 1, 2020 and all covenants were waived until March 2021. The remainder of the deficiency was not required to be cured. On June 1, 2020, we entered into the fourteenth amendment to the agreement to extend the due date of the borrowing base deficiency payment to July 31, 2020. On July 31, 2020, we entered into the fifteenth amendment to the agreement to not count the new Series 4 Preferred Units (Note 11) as debt and to allow the additional proceeds from the July 2020 capital raise to be retained by MorningStar. On November 1, 2021, we paid off the $100 million outstanding on this credit facility and replaced it with a new credit facility (See November 2021 MorningStar Partners Credit Facility) Prior to the pay off, we used the MorningStar Partners Credit Facility for general corporate purposes. In connection with entering into the credit facility and amendments, as of December 31, 2020, we had incurred financing fees and expenses of approximately $10.9 million before accumulated amortization of $9.8 million. The remaining costs were fully expensed when the facility was paid off in November 2021. Such amortized expenses are recorded as interest expense on the statements of operations. The weighted average interest rate on credit facility borrowings was 3.4% in 2021 and 3.8% in 2020.

November 2021 MorningStar Partners Credit Facility

On November 1, 2021, we entered into a new four-year, $165 million senior secured credit facility with certain commercial banks. The facility has a maturity date of November 1, 2025. We use the facility for general corporate purposes. In connection with entering into the credit facility, as of December 31, 2021, we incurred financing fees and expenses of approximately $2.7 million before accumulated amortization of $0.1 million. 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, in March and September, as well as upon requested interim redeterminations, by the lenders at their sole discretion. We also have the right to request additional borrowing base redeterminations each year at our discretion. Significant declines in commodity prices may result in a decrease in the borrowing base. These borrowing base declines can be offset by any commodity price hedges we enter. Our obligations under the credit facility are secured by all assets of the Company, including without limitation (i) our interest in the joint venture, (ii) all our deposit accounts, securities accounts, and commodities accounts, (iii) any receivables owed to us by the joint venture and (iv) any oil and gas properties owned directly by MorningStar or its wholly-owned subsidiaries. We are required to maintain (i) a current ratio greater than 1.0 and current assets shall include availability under the credit facility but shall exclude the fair value of derivative instruments and any advances under the facility and (ii) a ratio of total indebtedness-to-EBITDAX of not greater than 3.0 to 1.0. The totalindebtedness-to-EBITDAX calculation is limited to the joint venture's EBITDAX that has been paid in cash to MorningStar through distributions, MorningStar Operating's EBITDAX results and realized hedge gains less realized hedge losses and the consolidated expenses of MorningStar and its subsidiaries. EBITDAX means net income plus interest expense; income taxes paid; depreciation, depletion and amortization; exploration expenses, including workover expenses; non-cash charges including unrealized losses on derivative instruments; and, any extraordinary or non-recurring charges, minus any extraordinary or non-recurring income and any non-cash income including unrealized gains on derivative instruments. These covenants are not effective until March 31, 2022.

At our election, interest on borrowings under the credit facility is determined by reference to either the secured overnight financing rate ("SOFR") plus an applicable margin between 3.00% and 4.00% per annum (depending on the then-current level of borrowings under the Credit Facility) or the alternate base rate ("ABR") plus an applicable margin between 2.00% and 3.00% per annum (depending on the then-current level of borrowings under the Credit Facility). Interest is generally payable quarterly for loans bearing interest based on the ABR and at the end of the applicable interest period for loans bearing interest at SOFR. We are required to pay a commitment fee to the lenders under the Credit Facility, which accrues at a rate per annum of 0.5% on the average daily unused amount of the lesser of: (i) the maximum commitment amount of the lenders and (ii) the then-effective borrowing base. The weighted average interest rate on credit facility borrowings was 4.0% in 2021.

MorningStar Partners Loan

On September 30, 2016, MorningStar entered into a $27.1 million loan agreement with the joint venture. The proceeds for the loan were taken from the cash held by the offshore subsidiary of Exxon Mobil Corporation and the loan was assigned to the offshore subsidiary (Note 5). The loan matures on January 31, 2026, but is automatically extended should our credit facility be extended. In all instances, this loan will mature ninety-one days after the maturity of the current Morningstar credit facility. Interest on the loan is the lesser of (a) London Interbank Offered Rate ("LIBOR") plus three and one-quarter of one percent (3.25%) per annum, adjusted monthly or (b) the highest rate permitted by applicable law. The note is unsecured, but we are required to stay in compliance with terms of our current credit facility. The weighted average interest rate on loan was 3.4% in 2021 and 4.0% in 2020.

On September 30, 2020, $20.0 million was distributed to MorningStar Partners from the note receivable. This distribution was used by MorningStar Partners to pay down the outstanding loan with the joint venture.

Paycheck Protection Program Loans

On April 13, 2020, we received a loan of approximately $7.2 million under the US Government's Paycheck Protection Program from the Small Business Administration ("SBA"). Under the terms of the loan, it was required to be repaid beginning November 13, 2020 in equal installments until April 13, 2022, unless we qualified for loan forgiveness. The loan bore interest at a rate of 1% per annum. In August 2020, we sent in our loan forgiveness application for the entire loan amount. As a result of filing the application, we did not make any payments on the loan, nor did we accrue any interest on the loan in 2020. On June 14, 2021 we received notice that the loan was forgiven in full. We recorded this loan forgiveness as other income on the statements of operations.

On January 27, 2021, we received a second loan for $2.0 million under an extension of the US Government's Paycheck Protection Program from the SBA. On July 2, 2021 we received notice that the loan was forgiven in full. We recorded this loan forgiveness as other income on the statements of operations.

5. Note Receivable from Related Party

As of December 31, 2021, we, through our 5% ownership interest in investment assets at the joint venture, had a note receivable totaling $7.1 million outstanding with a highly-rated, offshore subsidiary of our joint venture partner. Under the terms of the agreement, there is no stated maturity date and, the joint venture may demand repayment of all or any portion of the outstanding balance on two business days' notice. Interest is earned based on the one-month LIBOR rate and is paid monthly. Interest income totaled less than $0.1 million in 2021 and $0.2 million in 2020.

On September 30, 2020, $20.0 million was distributed to MorningStar Partners from the note receivable. This distribution was used by MorningStar Partners to pay down the loan outstanding with the joint venture. See Note 4.

The note receivable is treated as a non-current asset, since the joint venture does not have any intention of demanding repayment of all or any portion of the outstanding balance at this time. Repayment would require the approval of the joint venture MMC.

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 2021 and 2020, we entered into futures contracts and swap agreements that effectively fixed natural gas and crude oil prices. See Note 10.

7. Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state and federal laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The following is a summary of asset retirement obligation activity for the years ended December 31, 2021 and 2020:

	(in thousands)	
	2021	**2020**
Asset retirement obligation, January 1	$ 100,670	$ 49,392
Revisions in the estimated cash flows(1)	(7,157)	(6,727)
Liability incurred upon acquiring and drilling wells	10,741	54,902
Liability settled upon sale of wells	(3,580)	—
Liability settled upon plugging and abandoning wells	(855)	(837)
Accretion of discount expense	4,670	3,940
Asset retirement obligation, December 31	104,489	100,670
Less current portion	(1,100)	(1,100)
Asset retirement obligation, long term	$ 103,389	$ 99,570

(1) Revisions in the estimated cash flows for the years ended December 31, 2021 and 2020 are primarily the result of revised cost estimates.

8. 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, costless collars, energy swaps, swaptions and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales (Note 10).

Fair Value of Financial Instruments

Because of their short-term maturity, the fair value of cash and cash equivalents, accounts receivable and accounts payable approximates their carrying values at December 31, 2021 and

2020. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	December 31, 2021		December 31, 2020	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Note receivable from related party	$ 7,132	$ 7,132	$ 7,131	$ 7,131
Long-term debt	$ (152,100)	$ (152,100)	$ (151,252)	$ (151,252)
Derivative asset	$ 15,544	$ 15,544	$ —	$ —
Derivative liability	$ (6,567)	$ (6,567)	$ —	$ —

The fair value of our note receivable from related party approximates the carrying amount because the interest rate is based on current market interest rates and can be called upon two business days' notice (Note 5). 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 4).

The fair value of our note receivable from related party (Note 5), net derivative asset (Note 10) and our long-term debt (Note 4) 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 notes receivable and net derivative asset. Since our counterparty is highly rated, the fair value of our note receivable from related party does not require an adjustment to account for the risk of nonperformance by the counterparty, however, an adjustment for counterparty credit risk has been applied to the net derivative asset.

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, 2021		December 31, 2020	
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Note receivable from related party	$ 7,132	$ —	$ 7,131	$ —
Long-term debt	$(152,100)	$ —	$(151,252)	$ —
Derivative asset	$ 15,544	$ —	$ —	$ —
Derivative liability	$ (6,577)	$ —	$ —	$ —

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.

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We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. We review our oil and natural gas properties by asset group. The estimated future net cash flows are based upon the underlying reserves and anticipated future pricing. An impairment loss is recognized if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of a particular asset, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of such assets. The fair value of the proved properties is measured based on the income approach, which incorporates a number of assumptions involving expectations of future product prices, which the Company bases on the forward-price curves, estimates of oil and gas reserves, estimates of future expected operating and capital costs and a risk adjusted discount rate of 10%. These inputs are categorized as Level 3 in the fair value hierarchy. We recognized an impairment of $0.0 million in the year ended December 31, 2021 and $134.1 million in the year ended December 31, 2020.

Commodity Price Hedging Instruments

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

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

	Asset Derivatives		Liability Derivatives	
	December 31,		December 31,	
(in thousands)	2021	2020	2021	2020
Derivatives not designated as hedging instruments:				
Crude oil futures and differential swaps	$ 2,342	$ —	$ (1,996)	$ —
Natural gas liquids futures	$ 685	$ —	$ (204)	$ —
Natural gas futures, collars and basis swaps	$ 12,517	$ —	$ (4,367)	$ —
Total	$ 15,544	$ —	$ (6,567)	$ —

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

(in thousands)	2021	2020
Net cash (received from) paid to counterparties	$ —	$ (26,192)
Non-cash change in derivative fair value	$ (8,977)	$ 2,887
Derivative fair value (gain) loss	$ (8,977)	$ (23,305)

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 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.

9. 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, energy swaps, swaptions and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We also enter costless price collars, which set a ceiling and floor price to hedge our exposure to price fluctuations on 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 9.

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl
January 2022—December 2022	3,500	$ 71.28
January 2023—December 2023	2,500	$ 68.87
January 2024—June 2024	2,000	$ 63.27

The price we receive for our oil production is generally different than the NYMEX price because of adjustments for delivery location (“basis”), relative quality and other factors. We have entered sell basis swap agreements that effectively fix the basis adjustment for the West Texas Midlands delivery location for the production and periods shown below.

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl(a)
January 2022—December 2022	3,000	$ 0.55

(a) Increases to NYMEX oil price for delivery location

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

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl(a)
January 2022—December 2022	5,000	$ 0.50
January 2023—December 2023	1,000	$ 0.68

(a) Increases to NYMEX oil price for roll component

Net settlement gains on oil futures and sell basis swap contracts increased oil revenues by $27.2 million in 2020. An unrealized gain in 2021 and an unrealized loss in 2020 to record the fair value of derivative contracts increased oil revenues by $0.3 million in 2021 and decreased oil revenues by $3.0 million in 2020.

Natural Gas Liquids

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

Production Period	Gallons per Day	Weighted Average NGL OPIS Price per Gallon
Ethane		
January 2022—December 2022	63,000	$ 0.33
January 2023—December 2023	63,000	$ 0.27
January 2024—June 2024	63,000	$ 0.23
Propane		
January 2022—December 2022	31,500	$ 1.01

An unrealized gain in 2021 to record the fair value of derivative contracts increased NGL revenues by $0.5 million in 2021.

Natural Gas

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

Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu
January 2022—December 2022	45,000	$ 4.23
January 2023—December 2023	35,000	$ 3.51
January 2024—June 2024	30,000	$ 3.26

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

Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu	
		Floor	Ceiling
January 2022—December 2022	15,000	$ 3.50	$ 5.85

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

Production Period	MMBtu per Day	Weighted Average Sell Basis Price per MMBTU(a)	
January 2022—December 2022	70,000	$	0.22
January 2023—December 2023	20,000	$	0.15

(a) Reductions to NYMEX gas price for delivery location

Net settlement losses on gas futures and sell basis swap contracts decreased gas revenues by $1.0 million in 2020. An unrealized gain to record the fair value of derivative contracts increased gas revenues by $8.2 million in 2021 and $0.1 million in 2020.

10. Partners' Capital

Partners' Units

Under the terms of the amended partnership agreement, there are two classes of units, Common Units and Preferred Units. The general partner establishes the number of authorized units and as of December 31, 2021, the general partner has not established the authorized number of Common Units.

In conjunction with an offering in August 2019, we created a new class of Preferred Units, Series 3 Preferred Units. Each Series 3 Preferred Unit cost $25 per unit and also included warrants to purchase an additional 1.5 common units for $1. The effect of the warrant is to provide 6.5 common units at a total cost of $26 or $4 per unit. The Series 3 Preferred Units will receive semi-annual distributions in the amount of $0.625 per unit. A holder of Series 3 Preferred Units will receive in-kind distributions of Common Units for their Series 3 Preferred Units. The number ofin-kind Common Units will accrue at a conversion price of $1.80 per unit. The semi-annual distributions are guaranteed and are to be paid in April and October. The Series 3 Preferred Units automatically convert to five Common Units no later than October 1, 2022 and the warrant is exercisable until October 1, 2023. The holder of Series 3 Preferred Units is entitled to cast the number of votes that the holder would be entitled to cast if the applicable Series 3 Preferred Unit was fully converted into Common Units.

In conjunction with an offering in July 2020, we created an additional class of Preferred Units, Series 4 Preferred Units. Each Series 4 Preferred Unit was issued at $95,000 per unit (an original issue discount of $5,000 per unit) and also included warrants equal to, in the aggregate, 20% non-dilutable common units, at the time of exercise. These warrants had a term of five years from the date of closing and an exercise price of $0.01 each. If holders of a majority of the warrants elected to exercise the warrants, then all warrants were required to be exercised at the same time. There was also a group of backstop investors that provided a minimum amount of capital of a least $35 million. These backstop investors received an arrangement fee in the form of warrants to purchase common units for $0.01 per common unit, with warrants equal to, in the aggregate, 10% non-dilutable common units at the time of exercise. These warrants had a term of 15 years. The Series 4 Preferred Units received a semi-annual payment of 12% paid-in-kind units at $0.20 per unit or 10% cash pay as permitted. The Company could call the Series 4 Preferred Units at any time and at a cost of $100,000 per unit plus any accrued dividends at such date. However, if we called the Series 4 Preferred Units on or prior to the second anniversary of the offering, we were required to pay $130,000 per unit. Beginning August 1, 2025, the Series 4 Preferred Units could be put back to us for repayment at a cost of $100,000 per unit plus any accrued dividends at such date. As a result of this offering, we issued 533.63 units for total proceeds of $50.4 million net of $0.3 million of offering costs. The proceeds were used to pay down $35 million on our Credit Facility (see Note 4) and the remainder was retained for future cash needs.

In conjunction with an offering in October 2021, we created an additional class of Preferred Units, Series 5 Preferred Units. Each Series 5 Preferred Unit was issued at $100,000 per unit. The Series 5 Preferred Units receive a semi-annual payment of 6.25% paid-in cash. The Series 5 Preferred Units automatically convert to Common Units at a rate of $0.80 per unit no later than October 15, 2024. In conjunction with this offering, all Series 4 Preferred Units were exchanged into Series 5 Preferred Units at a rate of 1.4 Series 5 Preferred Units for each Series 4 Preferred Unit. Additionally, all Series 4 warrants were converted to Common Units effective October 2021 at no cost to the warrant holder. The impact of the exchange of Series 4 Preferred Units to Series 5 Preferred Units coupled with the non-cash conversion of Series 4 warrants to Common Units accrued to the benefit of the Series 4 Preferred unitholders, who also own approximately 90% of the Common Units. The actual effect of this conversion was to transfer $22.7 million of value from the Common Unit holders to the Series 4 Preferred Unit holders. As a result of this offering, we issued 2,073.69 units for total proceeds of $132.6 million net of $0.1 million of offering costs. Subsequent to this offering, there were no Series 4 Preferred Units or warrants still outstanding.

The proceeds, in conjunction with cash on hand and borrowings under our credit facility, were used to acquire producing properties and a gas processing plant in the Permian Basin of New Mexico and CO2 assets in Colorado from Chevron (see Note 2).

Prior to April 1st of each year, the general partner shall determine the fair value of a Common Unit as of January 1st of such year. However, the general partner can change the fair value of a Common Unit should circumstances indicate that a material change in value has occurred. The fair value was determined to be $4.00 per Common Unit as of January 1, 2020. The fair value was determined to be $0.40 per Common Unit as of January 1, 2021. The fair value was determined to be $0.87 per Common Unit as of January 1, 2022. The fair value established by the general partner is used for all purposes until the next redetermination.

The following reflects our partners’ Common Unit and Preferred Unit activity for the years ended December 31, 2021 and 2020:

	2020			
(in thousands)	Common Units	Series 3 Preferred Units	Series 4 Preferred Units	Series 5 Preferred Units
Balance, beginning of period	179,198	1,372	—	—
Vesting of restricted units, net of income taxes	1,067	—	—	—
Common units surrendered to pay off share notes	(932)	—	—	—
Common units received in lieu of distribution	953	—	—	—
Preferred units purchased	—	—	1	—
Balance, December 31	180,286	1,372	1	—

	2021			
	Common Units	Series 3 Preferred Units	Series 4 Preferred Units	Series 5 Preferred Units
Balance, beginning of period	180,286	1,372	1	—
Vesting of restricted units, net of income taxes	3,000	—	—	—
Warrants converted to common units	137,438	—	—	—
Common units received in lieu of distribution	32,971	—	—	—
Preferred units purchased	—	—	—	1
Preferred units exchanged for new preferred units	—	—	(1)	1
Balance, December 31	353,695	1,372	—	2

Distributions

We paid in-kind distributions to our preferred unit holders of 33.0 million units with a value of $8.2 million during 2021 and 1.0 million units with a value of $1.6 million during 2020.

The determination of the amount of future distributions on the Common Units, if any, to be declared and paid is at the sole discretion of the general partner and will depend on our financial condition, earnings and cash flow from operations, the level of debt outstanding, the level of our capital expenditures, our future business prospects and other matters the general partner deems relevant.

See Note 12.

11. Employee Benefit Plans

401(k) Plan

We sponsor a 401(k) benefit plan that allows employees to contribute and defer a portion of their wages. Regardless of an employees' decision to participate in the 401(k) plan, we make a non-elective contribution equal to 3% of each employees' wages. Additionally, we have the ability to make a discretionary annual match as determined by the general partner. Employee contributions and non-elective contributions vest immediately while our matching contributions vest 100% upon completion of three years of service. All employees over 18 years of age may participate. The plan was put in place January 1, 2013. Company contributions under the plan were $0.7 million in 2021 and $0.7 million in 2020.

Unit Incentive Plans

Unit incentive awards under the 2012 Employee Equity Incentive Plan (2012 Plan) include unit awards which are subject to such restrictions as determined by the general partner. Under the terms of the 2012 Plan, 2.5 million units are available for grants of unit awards. On December 31, 2018, the Plan was amended to increase the amount of units available for grant to 4.5 million units.

A restricted unit is a unit that vests over a period of time and during such time is subject to forfeiture, and may contain such terms as the general partner shall determine. We intend the restricted units under the Plan to serve as a means of incentive compensation for performance. Therefore, participants will not pay any consideration for the restricted units they receive. If a grantee's employment or service relationship terminates for any reason other than death, the grantee's unvested restricted units will be automatically forfeited unless the general partner or the terms of the award agreement provide otherwise. Holders of restricted units generally have no voting, dividend or other rights of other unit holders.

	Grant Date Fair Value	Number of Units
Outstanding at December 31, 2019	$ 5.50	1,830,874
Vesting	(5.50)	(1,466,154)
Grants	—	—
Forfeitures	(5.50)	(364,720)
Outstanding at December 31, 2020	$ —	—

We recognized non-cash restricted unit compensation expense of $0.0 million in 2021 and $4.2 million in 2020 related to these shares. In conjunction with the July 2020, capital raise (Note 11), we vested the remaining unvested shares effective July 30, 2020. There was a fully-vested grant of 3,000,000 units in 2021.

12. Revenue from Contracts with Customers

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

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

	Year Ended December 31, 2021			
	Oil and condensate	Natural gas liquids	Natural gas	Total Revenues
	(in thousands)			
Revenue from customers	$ 69,625	$ 27,394	$ 122,348	$ 219,367
Unrealized gain (loss) on derivatives	346	481	8,150	8,977
Realized gain (loss) on derivatives	—	—	—	—
Total revenues	$ 69,971	$ 27,875	$ 130,498	$ 228,344

	Year Ended December 31, 2020			
	Oil and condensate	Natural gas liquids	Natural gas	Total Revenues
	(in thousands)			
Revenue from customers	$ 34,885	$ 8,660	$ 41,914	$ 85,459
Unrealized gain (loss) on derivatives	(2,957)	—	70	(2,887)
Realized gain (loss) on derivatives	27,142	—	(950)	26,192
Total Revenues	$ 59,070	$ 8,660	$ 41,034	$108,764

Natural Gas and NGL Sales

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

Oil and Condensate Sales

Oil production is sold at the wellhead under market-sensitive contracts at an index price, net of pricing differentials. The Company recognizes revenue when control transfers to the purchaser at the wellhead at the net price received from the customer. This treatment after the adoption of ASC 606 is consistent with the treatment under ASC 605 and has no impact on revenues or expenses on the statement of operations.

Production imbalances

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

Contract Balances

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

Performance Obligations

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.

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

13. Accrued Liabilities

Accrued liabilities consist of the following at December 31, 2021 and 2020:

	December 31, 2021	December 31, 2020
Accrued production expenses	$ 16,815	$ 11,083
Accrued severance taxes	3,511	1,182
Accrued ad valorem taxes	2,211	1,057
Accrued capital expenditures	541	663
Other accrued liabilities	680	172
Total accrued liabilities	$ 23,758	$ 14,157

14. Supplemental Cash Flow Information

The statement of cash flows excludes the following non-cash transactions:

- The following restricted share activity (Note 12):
  - No forfeitures in 2021 and forfeitures of 364,720 restricted units in 2020
- The payment of in-kind dividends of 32,970,580 units in 2021 and 952,639 units in 2020 (Note 12).
- The exchange of 533.63 Series 4 Preferred Units for 747.09 Series 5 Preferred Units (Note 11).
- Accrued capital expenditures were $0.5 million at December 31, 2021 and $0.7 million at December 31, 2020.

Interest payments totaled $4.1 million for in 2021 and $7.3 million in 2020. State income tax payments totaled $0.1 million in 2021 and $0.1 million in 2020.

15. Subsequent Events

We have evaluated subsequent events through the date the financial statements were available to be issued. See Note 2 for discussion of 2022 acquisition.

16. Supplementary Financial Information for Oil and Gas Producing Activities ***(Unaudited)***

All of our operations are directly related to oil and gas producing activities located in the United States primarily in the San Juan Basin of New Mexico and Colorado and the Permian Basin of West Texas and New Mexico.

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Costs Incurred Related to Oil and Gas Producing Activities

The following table summarizes costs incurred whether such costs are capitalized or expensed for financial reporting purposes for each year:

(in thousands)

	2021	2020
Acquisition of proved properties, net	$ 181,651	$ 15,138
Acquisition of unproved properties	67	307
Development	8,142	5,520
Asset retirement obligation incurred upon acquisition	10,741	54,902
Total costs incurred	$ 200,601	$ 75,867

Proved Reserves

Our proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods in which the cost of the required equipment is relatively minor compared with the cost of a new well. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors. Proved reserves exclude volumes deliverable to others under production payments or retained interests.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of 12-month average prices for oil and gas, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Discounted future net cash flows are calculated using a 10% rate. No provision is included for federal income taxes since our future net cash flows are not subject to taxation. However, our operations are subject to the Texas franchise tax.

Estimated well abandonment costs, net of salvage values, are deducted from the standardized measure usingyear-end costs and discounted at the 10% rate. Such abandonment costs are recorded as a liability on the consolidated balance sheet, using estimated values as of the projected abandonment date and discounted using a risk-adjusted rate at the time the well is drilled or acquired (Note 8).

The standardized measure does not represent management’s estimate of our future cash flows or the value of proved oil and natural gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as effected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

Proved Reserves *(in thousands)*	Oil (Bbls)	Natural Gas Liquids (Bbls)	Gas (Mcf)	Oil Equivalents (Boe)
December 31, 2019	24,002.0	4,586.2	107,103.4	46,438.8
Extensions, additions and discoveries	19.8	1.5	32.3	26.7
Revisions	(4,067.5)	(2,080.4)	(50,269.3)	(14,526.2)
Production	(940.1)	(860.2)	(22,131.6)	(5,488.9)
Purchase in place	590.6	6,664.1	208,438.1	41,994.4
December 31, 2020	19,604.8	8,311.2	243,172.9	68,444.8
Extensions, additions and discoveries	1,404.8	53.2	9,214.5	2,993.8
Revisions	1,297.6	7,235.3	149,715.2	33,485.4
Production	(1,033.0)	(1,088.8)	(30,589.7)	(7,220.1)
Purchase in place	27,296.6	3,513.6	7,763.0	32,104.0
December 31, 2021	48,570.8	18,024.5	379,275.9	129,807.9

Proved Developed Reserves *(in thousands)*	Oil (Bbls)	Natural Gas Liquids (Bbls)	Gas (Mcf)	Oil Equivalents (Boe)
December 31, 2020	9,787.7	8,311.2	218,396.9	54,498.4
December 31, 2021	30,207.9	17,434.2	353,214.9	106,511.3

Proved Undeveloped Reserves *(in thousands)*	Oil (Bbls)	Natural Gas Liquids (Bbls)	Gas (Mcf)	Oil Equivalents (Boe)
December 31, 2020	9,817.1	—	24,776.0	13,946.4
December 31, 2021	18,362.9	590.3	26,061.0	23,296.6

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves *(in thousands)*	December 31, 2021	December 31, 2020
Future cash inflows	$ 4,468,597	$ 1,049,560
Future costs:		
Production	(1,988,988)	(531,684)
Development	(365,289)	(297,570)
Future income tax	(4,110)	48
Future net cash flows	2,110,210	220,354
10% annual discount	(1,123,593)	(65,916)
Standardized measure	$ 986,617	$ 154,438

Changes in Standardized Measure of Discounted Future Net Cash Flows *(in thousands)*	For the Year Ended December 31, 2021	2020
Standardized measure, beginning of period	$ 154,438	$ 315,023
Revisions:		
Prices and costs	205,842	(261,185)
Quantity estimates	76,737	(29,789)
Income tax	(1,933)	789
Future development costs	2,715	18,370
Accretion of discount	15,444	31,502
Production rates and other	42,064	42,303
Net revisions	340,869	(198,010)
Additions and discoveries	20,272	150
Production	(93,042)	(7,085)
Development costs	13,973	11,639
Purchases in place	550,107	32,721
Net change	832,179	(160,585)
Standardized measure, December 31	$ 986,617(a)	$ 154,438(b)

(a) The December 31, 2021 standardized measure includes a reduction of $213.1 million ($213.6 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2021 includes accrued liability of $104.5 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions.

(b) The December 31, 2020 standardized measure includes a reduction of $201.9 million ($202.3 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2020 includes a liability of $100.7 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions.

Price and cost revisions are primarily the net result of changes in prices, based on beginning of year reserve estimates. Quantity estimate revisions are primarily the result of the extended economic life of proved reserves and proved undeveloped reserve additions attributable to increased development activity.

Average realized oil prices used in the estimation of proved reserves and calculation of the standardized measure were $64.76 for 2021 and $37.77 for 2020. Average realized natural gas liquids prices were $19.62 for 2021 and $7.38 for 2020. Average realized gas prices were $2.31 for 2021 and $1.03 for 2020. We used 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period.

MORNINGSTAR PARNTERS, L.P.

Unaudited Condensed Financial Statements

For the three months ended March 31, 2022 and 2021

MORNINGSTAR PARTNERS, L.P.
Condensed Balance Sheets

(in thousands)

	March 31, 2022 (Unaudited)	December 31, 2021
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 15,356	$ 7,547
Accounts receivable, net	48,862	34,124
Derivative fair value	1,651	10,632
Other	6,121	4,793
Total Current Assets	71,990	57,096
Property and Equipment, at cost—successful efforts method:		
Proved properties	1,380,916	1,376,476
Unproved properties	18,715	18,677
Other	70,559	69,254
Total Property and Equipment	1,470,190	1,464,407
Accumulated depreciation, depletion and amortization	(713,860)	(704,080)
Net Property and Equipment	756,330	760,327
Other Assets:		
Note receivable from related party	7,130	7,132
Derivative fair value	2,200	4,912
Other	2,983	3,353
Total Other Assets	12,313	15,397
TOTAL ASSETS	$ 840,633	$ 832,820
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities:		
Accounts payable	$ 8,934	$ 3,965
Accrued liabilities	25,925	23,758
Derivative fair value	61,483	6,450
Asset retirement obligation, current portion	1,100	1,100
Total Current Liabilities	97,442	35,273
Long-term Debt	137,100	152,100
Other Liabilities:		
Asset retirement obligation	104,924	103,389
Derivative fair value	24,744	117
Other liabilities	647	582
Total Other Liabilities	130,315	104,088
Commitments and Contingencies		
Partners' Capital:		
Partners' capital	475,776	541,359
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$ 840,633	$ 832,820

See accompanying notes to the Condensed Financial Statements

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MORNINGSTAR PARTNERS, L.P.
Condensed Statements of Operations (Unaudited)

(in thousands)

	Three months ended March 31, 2022	2021
REVENUES		
Oil and condensate	$ (2,530)	$ 10,875
Natural gas liquids	3,121	4,777
Gas	(10,129)	31,975
Total Revenues	(9,538)	47,627
EXPENSES		
Production	25,026	14,316
Exploration	87	44
Taxes, transportation and other	23,487	12,704
Depreciation, depletion and amortization	9,780	9,245
Accretion of discount in asset retirement obligation	1,477	1,320
General and administrative	396	(89)
Total Expenses	60,253	37,540
OPERATING (LOSS) INCOME	(69,791)	10,087
OTHER INCOME		
Other income	5,872	15
Interest income	6	3
Interest expense	(1,670)	(1,365)
NET (LOSS) INCOME	$ (65,583)	$ 8,740
PRO FORMA INFORMATION (UNAUDITED):		
Unaudited supplemental pro forma net income per common share (Note 2)		
Basic		
Diluted		
Unaudited supplemental pro forma weighted average unit0073 outstanding (Note 2)		
Basic		
Diluted		

See accompanying notes to the Condensed Financial Statements

MORNINGSTAR PARTNERS, L.P.
Condensed Statements of Cash Flows (Unaudited)

(in thousands)

	Three months ended March 31, 2022	2021
OPERATING ACTIVITIES		
Net (loss) income	$ (65,583)	$ 8,740
Adjustments to reconcile net (loss) income to net cash provided by operating activities net of effects of assets acquired and liabilities assumed:		
Depreciation, depletion and amortization	9,780	9,245
Accretion of discount in asset retirement obligation	1,477	1,320
Derivative fair value loss	106,517	—
Net cash received from (paid to) counterparties	(15,164)	—
Other non-cash items	168	155
Changes in operating assets and liabilities *(a)*	(8,530)	2,399
Cash Provided by Operating Activities	28,665	21,859
INVESTING ACTIVITIES		
Proved property acquisitions	(3,753)	—
Development costs	(696)	(1,423)
Unproved property acquisitions	(38)	(47)
Other property and asset additions	(1,305)	(22)
Cash Used by Investing Activities	(5,792)	(1,492)
FINANCING ACTIVITIES		
Proceeds from long-term debt	415,000	386,000
Payments on long-term debt	(430,000)	(406,000)
Debt issuance costs	(64)	(4)
Cash Used by Financing Activities	(15,064)	(20,004)
INCREASE IN CASH AND CASH EQUIVALENTS	7,809	363
Cash and Cash Equivalents, beginning of period	7,547	21,933
Cash and Cash Equivalents, end of period	$ 15,356	$ 22,296
(a) **Changes in Operating Assets and Liabilities**		
Accounts receivable	$ (14,738)	$ 846
Other current assets	(1,327)	(96)
Aid-in-construction	238	—
Current liabilities	7,395	1,730
Other operating liabilities	(98)	(81)
	$ (8,530)	$ 2,399

See accompanying notes to the Condensed Financial Statements

MORNINGSTAR PARTNERS, L.P.
Condensed Statements of Members' Equity (Unaudited)

(in thousands)

	Series 3 Preferred	Series 4 Preferred	Series 5 Preferred	Common	Total
Balances, December 31, 2021	$ 34,295	$ —	$206,074	$300,990	$541,359
Net loss	—	—	—	(65,583)	(65,583)
Balances, March 31, 2022	$ 34,295	$ —	$206,074	$235,407	$475,776

See accompanying notes to the Condensed Financial Statements

MORNINGSTAR PARTNERS, L.P.
Notes to Financial Statements

1. Organization and Description of the Business

MorningStar Partners, L.P. (MorningStar or the Company), is an independent oil and gas company that was formed as a Delaware limited partnership in January 2012 (with an effective inception of operations at January 18, 2012). The operations of MorningStar are governed by the provisions of the partnership agreement, as amended, executed by the general partner, MorningStar Oil & Gas, LLC (MSOG) and the limited partners. MSOG is the manager of MorningStar and is paid a quarterly management fee equal to 1% of revenue, less production expense, severance taxes and other deductions, at the discretion of the MorningStar board of directors. Under the amended partnership agreement, this management fee is currently suspended. MorningStar is governed by a board of directors made up of five officers and five outside investors. The agreement includes specific provisions with respect to the maintenance of the capital accounts of each of the Company's partners. Pursuant to applicable provisions of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act") and the limited partnership agreement, the partners have no liability for the debts, obligations and liabilities of MorningStar, except as expressly required in the limited partnership agreement or the Delaware Act. MorningStar will remain in existence unless and until dissolved in accordance with the terms of the partnership agreement.

MorningStar's assets include its investment in Cross Timbers Energy, LLC (Cross Timbers Energy), an unincorporated joint venture between XTO Energy Inc., HHE Energy Company and XH LLC (the XTO entities) and MorningStar. The XTO entities and MorningStar each own 50% of Cross Timbers Energy, and MorningStar is the manager of the joint venture. The joint venture is governed by a Member Management Committee (MMC) and is comprised of six representatives, three each from the XTO entities and MorningStar, with each group having one voting member. All matters that come before the MMC require the unanimous consent of the voting members. On the last day of each calendar quarter, Cross Timbers Energy distributes all excess cash to the members based on their ownership percentage of 50% each, except for earnings from the note receivable which is owned 95% by the XTO entities and 5% by MorningStar (Note 5). Cross Timbers Energy's properties are located primarily in the San Juan Basin of New Mexico and Colorado and the Permian Basin of West Texas and New Mexico.

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

2. Basis of Presentation and Significant Accounting Policies

The condensed financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and on the same basis as our audited financial statements as of December 31, 2021. The condensed balance sheet as of March 31, 2022 and the condensed statements of operations and cash flows for the periods presented herein are not audited but reflect all adjustments that are of a normal recurring nature and are necessary for a fair statement of results for the periods shown. Certain information and note disclosure normally included in annual financial statements have been omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission. Because the condensed 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 financial statements referred to above. The results and trends in these interim financial statements may not be indicative of results for the full year. The statement of operations includes unaudited supplemental pro forma information which gives effect to basic and diluted pro forma income per common unit for the three months ended March 31, 2022.

Significant Accounting Policies

For a complete description of MorningStar 's significant accounting policies, see our annual audited financial statements.

3. Acquisitions

In February 2022, MorningStar completed the acquisition of producing properties in the Permian Basin of Texas from Kaiser Francis for approximately \$3.8 million. Our purchase price allocation included \$4.0 million to proved properties and \$0.2 million to asset retirement obligation. The acquisition was funded by cash on hand.

In December 2021, MorningStar completed the acquisition of producing properties in the Permian Basin of Texas from Chevron for approximately \$43.8 million. Our purchase price allocation included \$47.2 million to proved properties and \$3.4 million to asset retirement obligation. The acquisition was funded by cash on hand and borrowings from our credit facility.

In November 2021, MorningStar completed the acquisition of producing properties and a gas processing plant in the Permian Basin of New Mexico and CO^2 assets in Colorado from Chevron for approximately \$175.4 million. Our purchase price allocation included \$145.2 million to proved properties, \$33.3 million to other properties, \$4.3 million to other current assets and \$7.4 million to asset retirement obligation. The acquisition was funded by cash on hand from the October 2021 capital raise and borrowings from our credit facility.

4. Related Party Transactions

We earned management fees from Cross Timbers Energy of \$1.5 million for the three months ended March 31, 2022 and \$1.7 million for the three months ended March 31, 2021.

5. Debt

(in thousands)	March 31, 2022	December 31, 2021
Credit Facility, 4.1% at March 31, 2022 and 4.0% at December 31, 2021	$ 130,000	$ 145,000
MorningStar Partners Loan, 3.4% at March 31, 2022 and 3.4% at December 31, 2021	$ 7,100	$ 7,100
Total Long-term Debt	$ 137,100	$ 152,100

November 2021 MorningStar Partners Credit Facility

On November 1, 2021, we entered into a new four-year, \$165 million senior secured credit facility with certain commercial banks. The facility has a maturity date of November 1, 2025. We use the facility for general corporate purposes. In connection with entering into the credit facility, as of December 31, 2021, we incurred financing fees and expenses of approximately \$2.8 million before accumulated amortization of \$0.3 million. 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, in March and September, as well as upon requested interim redeterminations, by the lenders at their sole discretion. We also have the right to request additional borrowing base redeterminations each year at our discretion. Significant declines in commodity prices may result in a decrease in the borrowing base. These borrowing base declines can be offset by any commodity price hedges we enter. Our obligations under the credit facility are secured by all assets of the Company, including without limitation (i) our interest in the Cross Timbers Energy, (ii) all our deposit accounts, securities accounts, and commodities accounts, (iii) any receivables owed to us by Cross Timbers Energy and (iv) any oil and gas properties owned directly by MorningStar or its wholly-owned subsidiaries. We are required to maintain (i) a current ratio greater than 1.0 and current assets shall include availability under the credit facility but shall exclude the fair value of derivative instruments and (ii) a ratio of total indebtedness-to-EBITDAX of not greater than 3.0 to 1.0. The total indebtedness-to-EBITDAX calculation is limited to Cross Timbers Energy's EBITDAX that has been paid in cash to MorningStar through distributions, MorningStar Operating's EBITDAX results and realized hedge gains less realized hedge losses and the consolidated expenses of MorningStar and its subsidiaries. EBITDAX means net income plus interest expense; income taxes paid; depreciation, depletion and amortization; exploration expenses, including workover expenses; non-cash charges including unrealized losses on derivative instruments; and, any extraordinary or non-recurring charges, minus any extraordinary or non-recurring income and any non-cash income including unrealized gains on derivative instruments. We were in compliance with all financial and other covenants of the credit facility, except the covenant regarding hedge volumes required as of March 31, 2022. We received a waiver for this exception in June 2022. We believe that we have a sufficient combination of resources and operating flexibility to ensure that we remain in compliance with our debt covenants for at least the next 12 months.

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

MorningStar Partners Loan

On September 30, 2016, MorningStar entered into a $27.1 million loan agreement with Cross Timbers. The proceeds for the loan were taken from the cash held by the offshore subsidiary of Exxon Mobil Corporation and the loan was assigned to the offshore subsidiary (Note 5). The loan matures on January 31, 2026, but is automatically extended should our credit facility be extended. In all instances, this loan will mature ninety-one days after the maturity of the current Morningstar credit facility. Interest on the loan is the lesser of (a) London Interbank Offered Rate ("LIBOR") plus three and one-quarter of one percent (3.25%) per annum, adjusted monthly or (b) the highest rate permitted by applicable law. The note is unsecured, but we are required to stay in compliance with terms of our current credit facility.

6. Note Receivable from Related Party

As of March 31, 2022 and December 31, 2021, we, through our 5% ownership interest in investment assets at Cross Timbers Energy, had a note receivable totaling $7.1 million outstanding with a highly-rated, offshore subsidiary of Exxon Mobil Corporation. Under the terms of the agreement, there is no stated maturity date and, Cross Timbers Energy may demand repayment of all or any portion of the outstanding balance on two business days' notice. Interest is earned based on the one-month LIBOR rate and is paid monthly. Interest income totaled less than $0.1 million in the first quarter of 2022 and 2021.

The note receivable is treated as anon-current asset, since Cross Timbers does not have any intention of demanding repayment of all or any portion of the outstanding balance at this time. Repayment would require the approval of the Cross Timbers Energy MMC.

7. Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state and federal laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The following is a summary of changes in MorningStar 's asset retirement obligation activity for the three months ended March 31, 2022:

	(in thousands)
Asset retirement obligation, January 1	$ 104,489
Liability incurred upon acquiring and drilling wells	250
Liability settled upon plugging and abandoning wells	(192)
Accretion of discount expense	1,477
Asset retirement obligation, March 31	106,024
Less current portion	(1,100)
Asset retirement obligation, long term	$ 104,924

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.

9. 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, costless collars, energy swaps, swaptions and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales (Note 10).

Fair Value of Financial Instruments

Because of their short-term maturity, the fair value of cash and cash equivalents, accounts receivable and accounts payable approximates their carrying values at December 31, 2021 and

2020. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	March 31, 2022		December 31, 2021	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Note receivable from related party	$ 7,130	$ 7,130	$ 7,132	$ 7,132
Long-term debt	$ (137,100)	$ (137,100)	$ (151,100)	$ (151,100)
Derivative asset	$ 3,851	$ 3,851	$ 15,544	$ 15,544
Derivative liability	$ (86,227)	$ (86,227)	$ (6,567)	$ (6,567)

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

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

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			
	March 31, 2022		December 31, 2021	
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Note receivable from related party	$ 7,130	$ —	$ 7,132	$ —
Long-term debt	$(137,100)	$ —	$(151,100)	$ —
Derivative asset	$ 3,851	$ —	$ 15,544	$ —
Derivative liability	$ (86,227)	$ —	$ (6,567)	$ —

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.

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

Commodity Price Hedging Instruments

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

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

	Asset Derivatives		Liability Derivatives	
(in thousands)	March 31, 2022	December 31, 2021	March 31, 2022	December 31, 2021
Derivatives not designated as hedging instruments:				
Crude oil futures and differential swaps	$ —	$ 2,342	$(42,854)	$ (1,996)
Natural gas liquids futures	$ —	$ 685	$ (6,714)	$ (204)
Natural gas futures, collars and basis swaps	$ 3,851	$ 12,517	$(36,659)	$ (4,367)
Total	$ 3,851	$ 15,544	$(86,227)	$ (6,567)

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:

	Three Months Ended March 31,	
(in thousands)	2022	2021
Net cash (received from) paid to counterparties	$ 15,164	$ —
Non-cash change in derivative fair value	$ 91,353	$ —
Derivative fair value (gain) loss	$ 106,517	$ —

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. 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.

10. Commodity Sales Commitments

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

We enter futures contracts, energy swaps, swaptions and basis swaps to hedge our exposure to price fluctuations on crude oil, natural gas liquids and natural gas sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We also enter costless price collars, which set a ceiling and floor price to hedge our exposure to price fluctuations on 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 9.

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl
April 2022—December 2022	3,500	$ 71.28
January 2023—December 2023	2,500	$ 68.87
January 2024—June 2024	2,000	$ 63.27

The price we receive for our oil production is generally different than the NYMEX price because of adjustments for delivery location (“basis”), relative quality and other factors. We have entered sell basis swap agreements that effectively fix the basis adjustment for the West Texas Midlands delivery location for the production and periods shown below.

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl(a)
April 2022—December 2022	3,000	$ 0.55

(a) Increases to NYMEX oil price for delivery location

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

Production Period	Bbls per Day	Weighted Average NYMEX Price per Bbl(a)
April 2022—December 2022	5,000	$ 0.50
January 2023—December 2023	1,000	0.68

(a) Increases to NYMEX oil price for roll component

Net settlement losses on oil futures and sell basis swap contracts decreased oil revenues by $7.7 million in the first three months of 2022 and $0.0 in the first three months of 2021. An unrealized loss decreased oil revenues by $43.2 million in the first three months of 2022 and $0.0 in the first three months of 2021.

Natural Gas Liquids

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

Production Period	Gallons per Day	Weighted Average NGL OPIS Price per Gallon
Ethane		
April 2022—December 2022	63,000	$ 0.33
January 2023—December 2023	63,000	$ 0.27
January 2024—June 2024	63,000	$ 0.23
Propane		
January 2022—December 2022	31,500	$ 1.01

Net settlement losses on NGL futures contracts decreased NGL revenues by $1.2 million in the first three months of 2022 and $0.0 in the first three months of 2021. An unrealized loss decreased NGL revenues by $7.2 million in the first three months of 2022 and $0.0 in the first three months of 2021.

Natural Gas

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

Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu
April 2022—December 2022	45,000	$ 4.23
January 2023—December 2023	35,000	$ 3.51
January 2024—June 2024	30,000	$ 3.26

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

Production Period	MMBtu per Day	Weighted Average NYMEX Price per MMBtu Floor	Ceiling
April 2022—December 2022	15,000	$ 3.50	$ 5.85

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

Production Period	MMBtu per Day	Weighted Average Sell Basis Price per MMBTU(a)
April 2022—December 2022	70,000	$ 0.22
January 2023—December 2023	20,000	$ 0.15

(a) Reductions to NYMEX gas price for delivery location

Net settlement losses on gas futures and sell basis swap contracts decreased gas revenues by $6.2 million in the first three months of 2022 and $0.0 in the first three months of 2021. An unrealized loss to record the fair value of derivative contracts decreased gas revenues by $41.0 million in the first three months of 2022 and $0.0 in the first three months of 2021.

11. Revenue from Contracts with Customers

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

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

	For the Three Months Ended March 31, 2022			
	Oil and condensate	Natural gas liquids	Natural gas	Total Revenues
	(in thousands)			
Revenue from customers	$ 48,407	$ 11,548	$ 37,024	$ 96,979
Unrealized gain (loss) on derivatives	(43,200)	(7,195)	(40,958)	(91,353)
Realized gain (loss) on derivatives	(7,737)	(1,232)	(6,195)	(15,164)
Total revenues	$ (2,530)	$ 3,121	$ (10,129)	$ (9,538)

	For the Three Months Ended March 31, 2021			
	Oil and condensate	Natural gas liquids	Natural gas	Total Revenues
	(in thousands)			
Revenue from customers	$ 10,875	$ 4,777	$ 31,975	$ 47,627
Unrealized gain (loss) on derivatives	—	—	—	—
Unrealized gain (loss) on derivatives	—	—	—	—
Total Revenues	$ 10,875	$ 4,777	$ 31,975	$ 47,627

Natural Gas and NGL Sales

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

Oil and Condensate Sales

Oil production is sold at the wellhead under market-sensitive contracts at an index price, net of pricing differentials. The Company recognizes revenue when control transfers to the purchaser at the wellhead at the net price received from the customer. This treatment after the adoption of ASC 606 is consistent with the treatment under ASC 605 and has no impact on revenues or expenses on the statement of operations.

Production imbalances

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

Contract Balances

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

Performance Obligations

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.

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

12. Accrued Liabilities

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

	March 31, 2022	December 31, 2021
Accrued production expenses	$ 18,392	$ 16,815
Accrued severance taxes	3,479	3,511
Accrued ad valorem taxes	2,301	2,211
Accrued capital expenditures	647	541
Other accrued liabilities	1,106	680
Total accrued liabilities	$ 25,925	$ 23,758

13. Supplemental Cash Flow Information

Interest payments totaled $1.5 million for the three months ended March 31, 2022 and $1.2 million for the three months ended March 31, 2021. Income tax payments were less than $0.1 million during the three months ended March 31, 2022 and 2021.

14. Subsequent Events

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

VACUUM PROPERTIES

Statement of Revenues and Direct Operating Expenses

Period from January 1, 2021 through October 31, 2021

Auditor Report

MorningStar Operating LLC
Statement of Revenues and Direct Operating
Expenses of the Vacuum Properties (as described in Note 1)

(in thousands)

	Period From January 1, 2021 to October 31, 2021
REVENUES	
Oil and condensate	$ 48,215
Natural gas liquids	1,935
Gas	178
Other	3,173
Total Revenues	53,501
DIRECT OPERATING EXPENSES	
Production	30,150
Taxes, transportation and other	5,062
Total Direct Operating Expenses	35,212
Revenues in Excess of Direct Operating Expenses	$ 18,289

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

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

(1) Basis of Presentation

On November 1, 2021, MorningStar Partners, LP and MorningStar Operating LLC ("MorningStar Entities") completed the acquisition from Chevron U.S.A. Inc., Chevron Midcontinent, L.P. and XBM Production, L.P. ("Chevron Entities") of producing properties and a gas processing plant in the Vacuum field of New Mexico and carbon dioxide (CO_2) assets in Colorado ("Vacuum Properties") for approximately $175.4 million. The purchase price was allocated primarily to proved properties and the gas processing and gathering plant. The acquisition was funded by cash contributions from MorningStar Partners limited partners and borrowings under the MorningStar Partners credit facility.

The accompanying audited statement includes revenues from oil, natural gas liquids and natural gas production and direct operating expenses associated with the Vacuum Properties and were derived from the Chevron Entities' consolidated historical accounting records. The accompanying statement varies from a complete income statement in accordance with accounting principles generally accepted in the United States of America in that they do not reflect certain indirect expenses that were incurred in connection with the ownership and operation of the Vacuum Properties including, but not limited to, general and administrative expenses, interest expense and income tax expense. These costs were not separately allocated to the Vacuum Properties in the accounting records of the Chevron Entities. 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 Vacuum Properties had it been a MorningStar Entities property due to the differing size, structure, operations and accounting policies of the Chevron Entities and the MorningStar Entities. 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 the MorningStar Entities will incur upon the allocation of the purchase price paid for the Vacuum Properties. Furthermore, no balance sheet has been presented for the Vacuum Properties because the acquired properties were not accounted for as a separate subsidiary or division of the Chevron Entities and complete financial statements are not available, nor has information about the Vacuum Properties' operating, investing and financing cash flows been provided for similar reasons. Accordingly, the historical Statement of Revenues and Direct Operating Expenses of the Vacuum 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 Vacuum 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 Chevron 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 as well as related income from the gas processing plant and sales of CO_2. The Chevron Entities recognize revenues 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 Chevron Entities expects to be entitled in exchange for the product.

During the period from January 1, 2021 to October 31, 2021, no customers accounted for more than 10% of the total revenues of the Vacuum Properties'.

Direct Operating Expenses—Direct operating expenses are recognized when incurred and consist of direct expenses of operating the Vacuum 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 Vacuum Properties may become subject to potential claims and litigation in the normal course of operations. The MorningStar Entities do 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 Vacuum Properties.

(4) Subsequent Events

The MorningStar Entities have evaluated events through July _, 2022, 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 Vacuum Properties as of November 1, 2021 and December 31, 2020 and for the period from January 1, 2021 to November 1, 2021 attributable to the Vacuum Properties. 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

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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 Vacuum 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 Vacuum 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 Vacuum Properties proved developed reserves as of November 1, 2021 and December 31, 2020 and for the period from December 31, 2020 to November 1, 2021.

	Oil (MBbl)	NGL (MBbl)	Gas (MMCF)	Total (MBOE)
November 1, 2021				
Proved Reserves				
Beginning balance, December 31, 2020	19,042	3,302	2,317	22,730
Revision of previous estimates	2,549	193	294	2,791
Production	(747)	(48)	(84)	(809)
Ending balance, November 1, 2021	20,844	3,447	2,527	24,712
Proved Developed Reserves December 31	12,426	2,738	1,950	15,489
Proved Undeveloped Reserves December 31	6,616	564	367	7,241
Proved Developed Reserves November 1	14,097	2,861	2,146	17,316
Proved Undeveloped Reserves November 1	6,747	586	381	7,396

Revision of previous estimates for all periods are primarily attributed to increases in commodity prices. As commodity prices increase, it extends the estimated useful life of the wells, thereby increasing the ultimate recoverable reserves.

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:

	November 1, 2021
Future cash inflows	$ 1,421,961
Future development and abandonment costs(a)	(48,151)
Future production expense	(712,056)
Future net cash flows	661,754
Discounted at 10% per year	(384,315)
Standardized measure of discounted future net cash flows	$ 277,439

(a) Future development and abandonment costs include $22.1 million as of November 1, 2021 and as of December 31, 2020, of undiscounted future asset retirement expenditures estimated as of those dates using current estimates of future abandonment costs.

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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 $58.41 for 2021 and $37.28 for 2020. Average realized natural gas liquids prices were $27.86 for 2021 and $18.61 for 2020. Average realized gas prices were $2.13 for 2021 and $0.91 for 2020.

- 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:

	Period From December 31, 2020 to November 1, 2021
Balance, beginning of year	$ 109,720
Oil and gas sales, net of production costs	(18,289)
Net change in sales prices and production costs	136,525
Changes in production rates (timing) and other	2,754
Revision of quantity estimates	35,757
Accretion of discount	10,972
Standardized measure of discounted future net cash flows	$ 277,439

APPENDIX A

SEVENTH AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP OF TXO ENERGY PARTNERS

[To be filed by amendment]

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APPENDIX B

GLOSSARY OF OIL AND GAS TERMS AND OTHER TERMS

The terms and abbreviations defined in this section are used throughout this prospectus:

"***Basin***." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"***Bbl***." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGL.

"***Boe***." One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to one Bbl of oil.

"***British Thermal Unit***" or "***Btu***." The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

"***Completion***." The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"***Developed acreage***." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"***Developed oil and gas reserves***." Developed oil and gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the related equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"***Development well***." A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"***Dry hole***." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"***Existing Owners***." means the holders of our existing equity interests prior to the reorganization transactions.

"***Field***." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations. For a complete definition of field, refer to the SEC's Regulation S-X, Rule 4-10(a)(15).

"***Formation***." A layer of rock which has distinct characteristics that differs from nearby rock.

"***Founders***." Our Chief Executive Officer, Keith A. Hutton, Brent W. Clum, our President of Business Operations and Chief Executive Officer our President of Production and Development, Scott T. Agosta, our Chief Accounting Officer, Vaughn O. Vennerberg II, our Executive Vice President, and Timothy L. Petrus, our former Executive Vice President.

"***Fracturing***" or "***fracture stimulation techniques***." The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"***Gross acres or gross wells***." The total acres or wells, as the case may be, in which a working interest is owned.

"***Held by Production***." acreage covered by a mineral lease that perpetuates a company's right to operate a property as long as the property produces a minimum paying quantity of oil or gas.

"***Horizontal drilling***." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"***Hydraulic fracturing***." The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"***Injection Wells***." a well in which fluids are injected rather than produced, the primary objective typically being to maintain reservoir pressure.

"***Lease operating expenses***." The expenses of lifting oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, workover, ad valorem taxes, insurance and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

"***MBbl***." One thousand barrels of crude oil, condensate or NGLs.

"***MBoe***." One thousand Boe.

"***Mcf***." One thousand cubic feet of natural gas.

"***MMBbl***." One million barrels of crude oil, condensate or NGL.

"***MMBoe***." One million Boe.

"***MMBtu***." One million Btu.

"***MMcf***." One million cubic feet of natural gas.

"***Net acres or net wells***." The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"***Net royalty acres***." Mineral ownership standardized to a 12.5%, or 1/8th, royalty interest.

"***NGL***." Natural gas liquids. Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

"***NYMEX***." The New York Mercantile Exchange.

"***OPIS***." Means the Oil Price Information Service.

"***PDP***." Proved developed producing reserves.

"***Possible reserves***." Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves. The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects. Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir. Where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

"***Probable reserves***." Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"***Productive well***." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"***Proved reserves***." Proved oil and natural gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. For a complete definition of proved crude oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

"***Proved undeveloped reserves ("PUD")***." Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that such locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time.

"***PV-10***." When used with respect to oil and natural gas reserves, PV-10 represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows. Calculation of PV-10 does not give effect to derivatives transactions. Our PV-10 has historically been computed on the same basis as our standardized measure of discounted future net cash flows ("Standardized Measure"), the most comparable measure under GAAP, but does not include a provision for either future well abandonment costs or the Texas gross margin tax. PV-10 is not a financial measure calculated or presented in accordance with GAAP and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of either well abandonment costs or income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

"***Recompletion***." The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"***Reservoir***." A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"***Spacing***." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"***Standardized Measure***." Standardized Measure is our standardized measure of discounted future net cash flows, which is prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of 12-month average prices for oil and gas, based on the first-day-of-the-month price for each month in the period, and year end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Discounted future net cash flows are calculated using a 10% rate. No provision is included for federal income taxes since our future net cash flows are not subject to taxation. However, our operations are subject to the Texas franchise tax. Estimated well abandonment costs, net of salvage values, are deducted from the standardized measure using year-end costs and discounted at the 10% rate. The standardized measure does not represent management's estimate of our future cash flows or the value of proved oil and natural gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as effected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

"***Undeveloped acreage***." Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

"***Unit***." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"***Wellbore***." The hole drilled by the bit that is equipped for oil and natural gas production on a completed well. Also called well or borehole.

"***Working interest***." The right granted to the lessee of a property to explore for and to produce and own oil and natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"***Workover***." Operations on a producing well to restore or increase production.

APPENDIX C

CAWLEY, GILLESPIE & ASSOCIATES SUMMARY RESERVE REPORT
(MORNINGSTAR PARTNERS, L.P.)

PART II
INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. Other expenses of issuance and distribution

The following table sets forth an itemized statement of the amounts of all expenses (excluding underwriting discounts and commissions) payable by us in connection with the registration of the common stock offered hereby. With the exception of the SEC registration fee, FINRA filing fee and NYSE listing fee, the amounts set forth below are estimates.

SEC registration fee	*
FINRA filing fee	*
NYSE listing fee	*
Accountants' fees and expenses	*
Legal fees and expenses	*
Engineering expenses	*
Printing and engraving expenses	*
Transfer agent and registrar fees	*
Miscellaneous	*
Total	*

* To be provided by amendment.

Item 14. Indemnification of Directors and Officers

TXO Energy Partners

Subject to any terms, conditions or restrictions set forth in the partnership agreement,Section 17-108 of the Delaware Revised Uniform Limited Partnership Act empowers a Delaware limited partnership to indemnify and hold harmless any partner or other persons from and against any and all claims and demands whatsoever. The section of the prospectus entitled "The Partnership Agreement—Indemnification" discloses that we will generally indemnify officers, directors and affiliates of the general partner to the fullest extent permitted by the law against all losses, claims, damages or similar events and is incorporated herein by this reference.

The underwriting agreement to be entered into in connection with the sale of the securities offered pursuant to this registration statement, the form of which will be filed as an exhibit to this registration statement, provides for indemnification of TXO Energy Partners and our general partner, their officers and directors, and any person who controls our general partner, including indemnification for liabilities under the Securities Act.

TXO Energy GP, LLC

Subject to any terms, conditions or restrictions set forth in the limited liability company agreement,Section 18-108 of the Delaware Limited Liability Company Act empowers a Delaware limited liability company to indemnify and hold harmless any member or manager or other person from and against any and all claims and demands whatsoever.

Under the amended and restated limited liability agreement of our general partner, in most circumstances, our general partner will indemnify the following persons, to the fullest extent permitted by law, from and against any and all losses, claims, damages, liabilities (joint or several), expenses (including legal fees and expenses), judgments, fines, penalties, interest, settlements or other amounts arising from any and all claims, demands, actions, suits or proceedings (whether civil, criminal, administrative or investigative):

- any person who is or was an affiliate of our general partner (other than us and our subsidiaries);
- any person who is or was a member, partner, officer, director, employee, agent or trustee of our general partner or any affiliate of our general partner;
- any person who is or was serving at the request of our general partner or any affiliate of our general partner as an officer, director, employee, member, partner, agent, fiduciary or trustee of another person; and
- any person designated by our general partner.

Our general partner will purchase insurance covering its officers and directors against liabilities asserted and expenses incurred in connection with their activities as officers and directors of our general partner or any of its direct or indirect subsidiaries.

Item 15. Recent Sales of Unregistered Securities

Prior to the initial public offering the Existing Holders in TXO Energy Partners will contribute all outstanding equity interest into a new parent company, MorningStar Partners II, L.P., a Delaware limited partnership.

In September 2019, the Company entered into the Series 3 Preferred Unit Purchase Agreement, pursuant to which the Company issued 1,372,000 Series 3 Preferred Units for $34.3 million, including reduction of $1.4 million in payable due to general partner in lieu of payment, to meet certain financing needs including reducing the Company’s then outstanding debt.

In July 2020, the Company entered into the Series 4 Preferred Unit Purchase Agreement, pursuant to which the Company issued 534 Series 4 Preferred Units for $50.7 million to pay down debt. The proceeds from the offering were used to pay down debt.

In October 2021, the Company entered into the Series 5 Preferred Unit Purchase Agreement, pursuant to which the Company issued 1,327 Series 5 Preferred Units for $132.7 million. The proceeds from the offering were used to meet certain financing needs.

The above issuances did not involve any underwriters, underwriting discounts or commissions, or any public offering and we believe is exempt from the registration requirements of the Securities Act of 1933 by virtue of Section 4(2) thereof and/or Regulation D promulgated thereunder.

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Item 16. Exhibits and financial statement schedules

Exhibit Number	Description
*1.1	Form of Underwriting Agreement
*3.1	Certificate of Limited Partnership of MorningStar Partners, L.P.
*3.2	Form of Seventh Amended Agreement of Limited Partnership of TXO Energy Partners, L.P.
*3.3	Certificate of Formation of MorningStar Oil & Gas, LLC
*3.4	Form of Amended and Restated Limited Liability Company Agreement of TXO Energy GP, LLC
*5.1	Opinion of Latham & Watkins LLP as to the legality of the securities being registered
*8.1	Opinion of Latham & Watkins LLP relating to tax matters
*10.1	Credit Agreement, among MorningStar Partners, L.P., the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent, dated November 1, 2021
*10.2	Amendment No. 1 to the Credit Agreement and Borrowing Base Agreement
*10.3	Form of TXO GP, LLC Long-Term Incentive Plan
*10.4	Limited Liability Company Agreement of Cross Timbers Energy, LLC, dated as of June 13, 2013, by and among XTO Energy Inc., XH LLC, HHE Energy Company and MorningStar Partners, L.P.
*10.5	Form of Services Agreement
*21.1	List of Subsidiaries of TXO Energy Partners, L.P.
*23.1	Consent of KPMG LLP for Partnership Financials
*23.2	Consent of KPMG LLP for Chevron Vacuum Acquisition Financials
*23.3	Consent of Cawley, Gillespie & Associates
*23.4	Consent of Latham & Watkins LLP (contained in Exhibit 5.1)
*23.5	Consent of Latham & Watkins LLP (contained in Exhibit 8.1)
*24.1	Powers of Attorney (included on signature page)
*99.1	Report of Cawley, Gillespie & Associates of reserves of MorningStar Partners, L.P. as of January 1, 2022
*99.2	Consent of Phillip R. Kevil
*99.3	Consent of Rick J. Settle
*99.4	Consent of J. Luther King, Jr.
*99.5	Consent of William H. Adams III
*107	Filing Fee Table.

* To be filed by amendment.

Item 17. Undertakings

The undersigned registrant hereby undertakes to provide to the underwriters at the closing specified in the underwriting agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the SEC such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this registration statement as of the time it was declared effective.

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Fort Worth, State of Texas, on , 2022.

MorningStar Partners, L.P.

By: MorningStar Oil & Gas, LLC, its general partner

By: ______________________________
Name: Bob R. Simpson
Title: Chief Executive Officer

Each person whose signature appears below appoints Brent W. Clum and Scott T. Agosta, and each of them, any of whom may act without the joinder of the other, as his or her true and lawful attorneys in fact and agents, with full power of substitution and resubstitution, for him or her and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post effective amendments) to this Registration Statement and any Registration Statement (including any amendment thereto) for this offering that is to be effective upon filing pursuant to Rule 462(b) under the Securities Act of 1933, as amended, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys in fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or would do in person, hereby ratifying and confirming all that said attorneys in fact and agents or any of them or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, as amended, this Registration Statement has been signed below by the following persons in the capacities and the dates indicated.

Name	Title	Date
/s/ Bob R. Simpson	Chief Executive Officer (principal executive officer)	, 2022
/s/ Brent W. Clum	President of Business Operations and Chief Financial Officer (principal financial officer)	, 2022
/s/ Scott T. Agosta	Chief Accounting Officer (principal accounting officer)	, 2022
/s/ Phillip R. Kevil	Director	, 2022
/s/ Rick J. Settle	Director	, 2022
/s/ J. Luther King, Jr.	Director	, 2022
/s/ William H. Adams III	Director	, 2022