**Risk Factors Comparison 2025-02-20 to 2024-02-22 Form: 10-K**

**Legend:** **New Text** ~~Removed Text~~ Unchanged Text Moved Text Section

Risks Related to Our Business Our cash distributions are highly dependent on oil and natural gas prices, which have historically been very volatile. Our quarterly cash distributions depend significantly on the prices realized from the sale of ~~oil and, in particular,~~ natural gas **and, in particular, oil** . Historically, the markets for oil and natural gas have been volatile and may continue to be volatile in the future. Various factors that are beyond our control will affect prices of oil and natural gas, such as: ● the worldwide and domestic supplies of oil and natural gas; ● the ability of the members of the Organization of Petroleum Exporting Countries and others to agree to and maintain oil prices and production controls; ● political instability or armed conflict in oil- producing regions; ● the price and level of foreign imports; ● the level of consumer demand; ● the price and availability of alternative fuels; ● the availability of pipeline capacity **; ● technological advances affecting energy consumption** ; ● weather conditions; ● domestic and foreign governmental regulations and taxes; and ● the overall economic environment. Lower oil and natural gas prices may reduce the amount of oil and natural gas that is economic to produce and may reduce our revenues and operating income. The volatility of oil and natural gas prices reduces the accuracy of estimates of future cash distributions to unitholders. We do not control operations and development of the Royalty Properties or the properties underlying the NPIs that the Operating Partnership does not operate, which could impact the amount of our cash distributions. As the owner of a fractional undivided mineral or royalty interest, we do not control the development of the Royalty or NPI properties or the volumes of oil and natural gas produced from them, and our ability to influence development of nonproducing properties is severely limited. Also, since one of our stated business objectives is to avoid the generation of unrelated business taxable income, we are prohibited from participation in the development of our properties as a working interest or other expense- bearing owner. The decision to explore or develop these properties, including infill drilling, exploration of horizons deeper or shallower than the currently producing intervals, and application of enhanced recovery techniques will be made by the operator and other working interest owners of each property (including our lessees) and may be influenced by factors beyond our control, including but not limited to oil and natural gas prices, interest rates, budgetary considerations and general industry and economic conditions. Our unitholders are not able to influence or control the operation or future development of the properties underlying the NPIs. The Operating Partnership is unable to influence the operations or future development of properties that it does not operate. The current operators of the properties underlying the NPIs are under no obligation to continue operating the underlying properties. Our unitholders do not have the right to replace an operator. Our lease bonus revenue depends in significant part on the actions of third parties, which are outside of our control. Significant portions of the Royalty Properties are unleased mineral interests. With limited exceptions, we have the right to grant leases of these interests to third parties. We anticipate receiving cash payments as bonus consideration for granting these leases in most instances. Our ability to influence third parties' decisions to become our lessees with respect to these nonproducing properties is severely limited, and those decisions may be influenced by factors beyond our control, including but not limited to oil and natural gas prices, interest rates, budgetary considerations, and general industry and economic conditions. The Operating Partnership may transfer or abandon properties that are subject to the NPIs. Our General Partner, through the Operating Partnership, may at any time transfer all or part of the properties underlying the NPIs. Our unitholders are not entitled to vote on any transfer; however, any such transfer must also simultaneously include the NPIs at a corresponding price. The Operating Partnership or any transferee may abandon any well or property if it reasonably believes that the well or property can no longer produce in commercially economic quantities. This could result in termination of the NPIs relating to the abandoned well **or property** . Cash distributions are affected by production and other costs, most of which are outside of our control. The cash available for distribution that comes from our royalty and mineral interests, including the NPIs, is directly affected by increases in production costs and other costs. Most of these costs are outside of our control, including costs of regulatory compliance and severance and other similar taxes. Other expenditures are dictated by business necessity, such as drilling additional wells in response to the drilling activity of others. Our oil and natural gas reserves and the underlying properties are depleting assets, and there are limitations on our ability to replace them. Our revenues and distributions depend in large part on the quantity of oil and natural gas produced from properties in which we hold an interest. Over time, all of our producing oil and natural gas properties will experience declines in production due to depletion of their oil and natural gas reservoirs, with the rates of decline varying by property. Replacement of reserves to maintain production levels requires maintenance, development or exploration projects on existing properties, or the acquisition of additional properties. The timing and size of maintenance, development or exploration projects will depend on the market prices of oil and natural gas and on other factors beyond our control. All of the decisions regarding implementation of such projects, including drilling or exploration on any unleased and undeveloped acreage, will be made by third parties. Our ability to increase reserves through future acquisitions is limited by restrictions on our use of operating cash and limited partnership interests for acquisitions and by our General Partner' s obligation to use all reasonable efforts (such as limiting acquisitions to acquisitions of NPIs and royalty interests) to avoid unrelated business taxable income. In addition, the ability of affiliates of our General Partner to pursue business opportunities for their own accounts without tendering them to us in certain circumstances may reduce the acquisitions presented to us for consideration. Acreage must be drilled before lease expiration, generally within three years, in order to hold the acreage by production. Our operators’ failure to drill sufficient wells to hold acreage may result in the deferral of prospective drilling opportunities. In addition, our ORRIs may terminate if the underlying acreage is not drilled before the expiration of the applicable lease or if the lease otherwise terminates. Leases on oil and natural gas properties typically have a term of three years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. In addition, even if production or drilling is established during such primary term, if production or drilling ceases on the leased property, the lease typically terminates, subject to certain exceptions. Any reduction in our operators' drilling programs, either through a reduction in capital expenditures or the unavailability of equipment, services, or supplies, could result in the expiration of existing leases. If the lease governing any of our mineral interests expires or terminates, all development rights typically revert back to us, and we may seek new lessees to explore and develop such mineral interests or in some states remain unleased. If the lease underlying any of our ORRIs expires or terminates, our ORRIs that are derived from such lease will also terminate. Any such expirations or terminations of our leases or our ORRIs could materially and adversely affect our financial condition, results of operations and cash flow. If our operators suspend our right to receive royalty payments due to title or other issues, our business, financial condition, results of operations and cash flows may be adversely affected. Our business depends, in part, on acquisitions which contribute to the growth of our reserves, production and cash generated from operations. In connection with these acquisitions, we are conveyed record title to mineral and royalty interests. Due to such changes in ownership of mineral interests, the operator of the underlying property has the right, at such operator' s discretion, to investigate and verify the title and ownership of mineral and royalty interests with respect to the properties it operates. If any title or ownership issues are not resolved to its reasonable satisfaction in accordance with customary industry standards, the operator has the right to suspend payment of the related royalty. If an operator of our properties is not satisfied with the documentation we provide to validate our ownership, such operator may suspend our royalty payment until such issues are resolved, at which time we would receive the full royalty payment which we would have otherwise received if not for the payment being suspended, without interest. Certain of our operators impose burdensome documentation requirements for title transfer and may keep royalty payments in suspense for significant periods of time. During the time that an operator puts our assets in pay suspense, we would not receive the applicable mineral or royalty payment owed to us from sales of the underlying oil or natural gas related to such mineral or royalty interest. If a significant amount of our royalty interests are placed in suspense, our results of operations and cash flow may be materially affected. Title to the properties in which we have an interest may be impaired by title defects. In our discretion, we may elect not to incur the expense of retaining lawyers to examine the title to our royalty and mineral interests. In such cases, we would rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before acquiring a specific royalty or mineral interest. The existence of a material title deficiency can have a significant adverse effect on the value of an interest and can further materially adversely affect our results of operations, financial condition and cash flows. We may experience delays in received royalty payments and be unable to replace operators that do not make required royalty payments, and we may not be able to terminate our leases with defaulting lessees if any of the operators on those leases declare bankruptcy. We may experience delays in receiving royalty payments from our operators, including as a result of delayed division orders received by our operators. Typically, the failure of an operator to make royalty payments to which we are entitled, gives us the right to terminate the lease, repossess the property and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement operator. However, we cannot guarantee finding a suitable replacement operator in such a circumstance and if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing operator could be subject to a bankruptcy proceeding under Title 11 of the United States Code (the " Bankruptcy Code "), in which case our right to enforce or terminate the lease for any defaults, including non- payment, may be substantially delayed or otherwise at risk. In general, in a proceeding under the Bankruptcy Code, the bankrupt operator would have an extended period of time to decide whether to ultimately reject or assume the lease, which could significantly delay or prevent the execution of a new lease or the assignment of the existing lease to a replacement operator. In the event that an operator rejects the lease, our ability to collect amounts owed to us would be substantially delayed, and our ultimate recovery may be only a fraction of the amount owed or nothing. In addition, if we are able to enter into a new lease with a new operator, there is no guarantee that such replacement operator will achieve the same levels of production or sell oil or natural gas at the same price as the operator it replaced. We do not currently plan to enter into hedging arrangements with respect to the oil and natural gas production from our properties, and we will be exposed to the impact of decreases in the price of oil and natural gas. We do not currently plan to enter into hedging arrangements to establish, in advance, a price for the sale of the oil and natural gas produced from our properties. As a result, although we may realize the benefit of any short- term increase in the price of oil and natural gas, we will not be protected against decreases in the price of oil and natural gas or prolonged periods of low commodity prices, which could materially adversely affect our business, results of operation and cash available for distribution. If we enter into hedging arrangements in the future, it may limit our ability to realize the benefit of rising prices and may result in hedging losses. Competition in the oil and natural gas industry is intense, which may adversely affect our and our operators' ability to succeed. The oil and natural gas industry is intensely competitive, and the operators of our properties compete with other companies that may have greater resources or greater access to capital. Many of these companies explore for and produce oil and natural gas, carry on midstream and refining operations, and market petroleum and other products on a regional, national or worldwide basis. In addition, these companies may have a greater ability to continue exploration activities during periods when market prices of oil and natural gas are low. Our operators' larger competitors may be able to better address the burden of present and future federal, state, local and other laws and regulations more easily than our operators can, which could adversely affect our operators' competitive position. Our operators may have access to fewer financial and human resources than many companies in our operators' industry and may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties. Furthermore, the oil and natural gas industry has experienced recent consolidation amongst some operators, which has resulted in certain instances of combined companies with larger resources. Such combined companies may compete against our operators or, in the case of consolidation amongst our operators, may choose to focus their operations on areas outside of our properties. In addition, we cannot guarantee our ability to acquire additional properties and to discover reserves in the future as this will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Drilling activities on our properties may not be productive, which could have an adverse effect on future results of operations and financial condition. The Operating Partnership may participate in drilling activities in limited circumstances on the properties underlying the NPIs, and third parties may undertake drilling activities on our properties. Any increases in our reserves will come from such drilling activities or from acquisitions. Drilling involves a wide variety of risks, including the risk that no commercially productive oil or natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be delayed or canceled as a result of a variety of factors, including: ● pressure or irregularities in formations; ● equipment failures or accidents; ● unexpected drilling conditions; ● shortages or delays in the delivery of equipment; ● adverse weather conditions; and ● disputes with drill- site owners. Future drilling activities on our properties may not be successful. If these activities are unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. In addition, under the terms of the NPIs, the costs of unsuccessful future drilling on the working interest properties that are subject to the NPIs will reduce amounts payable to us under the NPIs by 96. 97 % of these costs. Our ability to identify and capitalize on acquisitions is limited by contractual provisions and substantial competition. Our partnership agreement limits our ability to acquire oil and natural gas properties in the future, especially for consideration other than our limited partnership interests or cash proceeds of a securities offering. Because of the limitations on our use of operating cash for acquisitions and on our ability to accumulate operating cash for acquisition purposes, we may be required to attempt to effect acquisitions by first selling our securities to raise cash or by issuing our limited partnership interests. However, we may be unable to sell our securities in sufficient quantities and for sufficient consideration to provide adequate consideration to fund an acquisition, and sellers of properties we would like to acquire may be unwilling to take our limited partnership interests in exchange for properties. Our partnership agreement obligates our General Partner to use all reasonable efforts to avoid generating unrelated business taxable income. Accordingly, to acquire working interests we would have to arrange for them to be converted into overriding royalty interests, net profits interests, or another type of interest that does not generate unrelated business taxable income. Third parties may be less likely to deal with us than with a purchaser to which such a condition would not apply. These restrictions could prevent us from pursuing or completing business opportunities that might benefit us and our unitholders, particularly unitholders who are not tax- exempt investors. The duty of affiliates of our General Partner to present acquisition opportunities to our Partnership is limited, pursuant to the terms of the business opportunities agreement. Accordingly, business opportunities that could potentially be pursued by us might not necessarily come to our attention, which could limit our ability to pursue a business strategy of acquiring oil and natural gas properties. We compete with other companies and producers for acquisitions of oil and natural gas interests. Many of these competitors have substantially greater financial and other resources than we do. Any future acquisitions will involve risks that could adversely affect our business, which our unitholders generally will not have the opportunity to evaluate. Our current strategy contemplates that we may grow through acquisitions and development of our undeveloped property. We expect to participate in discussions relating to potential acquisition and investment opportunities. If we consummate any additional acquisitions and investments, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in connection with the acquisition, unless the terms of the acquisition require approval of our unitholders. Additionally, our unitholders will bear 100 % of the dilution from issuing new common units while receiving essentially 96 % of the benefit as 4 % of the benefit goes to our General Partner. Acquisitions and business expansions involve numerous risks, including assimilation difficulties, unfamiliarity with new assets or new geographic areas and the diversion of management' s attention from other business concerns. In addition, the success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attributable to reserves and to assess possible environmental liabilities. Our review and analysis of properties prior to any acquisition will be subject to uncertainties and, consistent with industry practice, may be limited in scope. We may not be able to successfully integrate any oil and natural gas properties that we acquire into our operations, or we may not achieve desired profitability objectives. A natural disaster or catastrophe could damage pipelines, gathering systems and other facilities that service our properties, which could substantially limit our operations and adversely affect our cash flow. If gathering systems, pipelines or other facilities that serve our properties are damaged by any natural disaster, accident, catastrophe or other event, our income could be significantly interrupted. Any event that interrupts the production, gathering or transportation of our oil and natural gas, or which causes us to share in significant expenditures not covered by insurance, could adversely impact the market price of our limited partnership units and the amount of cash available for distribution to our unitholders. We do not carry business interruption insurance. A significant portion of the properties subject to the NPIs are geographically concentrated, which could cause net proceeds payable under the NPIs to be impacted by regional events. A significant portion of the properties subject to the NPIs are properties located in the Bakken region and Permian Basin. Because of this geographic concentration, any regional events, including natural disasters that increase costs, reduce availability of equipment, services, or supplies, reduce demand or limit production may impact the net proceeds payable under the NPIs more than if the properties were more geographically diversified. Under the terms of the NPIs, much of the economic risk of the underlying properties is passed along to us. Under the terms of the NPIs, virtually all costs that may be incurred in connection with the properties, including overhead costs that are not subject to an annual reimbursement limit, are deducted as production costs or excess production costs in determining amounts payable to us. Therefore, to the extent of the revenues from the burdened properties, we bear 96. 97 % of the costs of the working interest properties. If costs exceed revenues, we do not receive any payments under the NPIs. However, except as described below, we are not required to pay any excess costs. The terms of the NPIs provide for excess costs that cannot be charged currently because they exceed current revenues to be accumulated and charged in future periods, which could result in us not receiving any payments under the NPIs until all prior uncharged costs have been recovered by the Operating Partnership. Our cash flow is subject to operating hazards and unforeseen interruptions for which we may not be fully insured. Neither we nor the Operating Partnership are fully insured against certain risks, either because such full insurance is not available or because of high premium costs. Operations that affect the properties are subject to all of the risks normally incident to the oil and natural gas business, including blowouts, cratering, explosions, and pollution and other environmental damage, any of which could result in substantial decreases in the cash flow from our royalty interests and other interests due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean- up responsibilities, regulatory investigations and penalties and suspension of operations. Any uninsured costs relating to the properties underlying the NPIs will be deducted as a production cost in calculating the net proceeds payable to us. Governmental policies, laws and regulations could have an adverse impact on our business and cash distributions. Our business and the properties in which we hold interests are subject to federal, tribal, state and local laws and regulations relating to the oil and natural gas industry as well as regulations relating to environmental, health, and safety matters. These laws and regulations can have a significant impact on production and costs of production. Regulators have the ability, directly or indirectly, to limit production from our properties, and such limitations or changes in those limitations could negatively impact us in the future. Cyber incidents or attacks targeting our systems and infrastructure used by the oil and natural gas industry may adversely impact our operations, and if we are unable to obtain and maintain adequate protection of our data, our business may be adversely impacted. We and our operators increasingly rely on information technology systems to operate our respective businesses, and the oil and natural gas industry depends on digital technologies in exploration, development, production, and processing activities. Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. Our technologies, systems, networks, including third party software, cloud services and other internally and externally hosted hardware and software platforms, and those of the operators of our properties, vendors, suppliers, and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of business activities. In addition, certain cyber incidents, such as surveillance, may remain undetected for some period of time. While we utilize various procedures and controls to mitigate exposure to such risk, cyber incidents and attacks are evolving and unpredictable. Our information technology systems and any insurance coverage for protecting against cybersecurity risks may not be sufficient. As cyber security threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. It is possible that our business, finances, systems and assets could be compromised in a cyber attack. The Partnership may be adversely affected by price volatility in the oil and natural gas markets. Historically, there has been price volatility in the oil and natural gas markets, which have been impacted by a number of factors, including actions by oil producing nations. For example, after OPEC and a group of oil producing nations led by Russia failed in March 2020 to agree on oil production cuts, Saudi Arabia announced that it would cut oil prices and increase production, leading to a sharp decline in oil and natural gas prices. While OPEC, Russia and other oil producing countries reached an agreement in April 2020 to reduce production levels, and U. S. production declined, oil prices remained lower than in previous years on account of an oversupply of oil and natural gas, with a simultaneous decrease in demand as a result of the impact of COVID- 19 on the global economy. Thereafter, in 2021, oil and natural gas prices significantly rebounded. ~~Although we~~ **However, global military conflicts, fluctuating interest rates, changes in tariff rates, global supply chain disruptions, concerns about a potential economic downturn or recession, recent measures to combat persistent inflation, and actions taken by OPEC and its non- OPEC allies, collectively OPEC ,** ~~continue~~ **continued** to ~~see sustained improvements in~~ **contribute to economic and** pricing **volatility during 2024. Oil** ~~, on account of a number of factors, the oil~~ and natural gas markets remain subject to price volatility, which may have a material adverse effect on our cash distributions in periods of lower prices. During periods of substantial declines in prices, such as in 2020, oil and natural gas operators on our properties may suspend drilling programs, which would impact our revenues and operating income. In the event that any wells on our properties are shut- in, restarting wells may require significant costs from our operators, and we cannot guarantee that they would be able to restart at the same level. Moreover, due to the extremely volatile market conditions, we are unable to predict the degree or duration of any adverse impact on our operations and financial condition and other risks in our industry may be enhanced by such conditions. Continuing or worsening inflationary issues and associated changes in federal monetary policy may result in increases to the costs of the goods, services and labor used by our operators, which could cause their capital expenditures and operating costs to rise and may delay or restrict their exploration and development activities. ~~The rate~~ **Recently, the U. S. has had periods** of **high** inflation ~~in the U. S. has been steadily increasing since 2021 and through 2022~~ . These inflationary pressures may result in increases to the costs of the goods, services and labor used by our operators, which could cause their capital expenditures and operating costs to rise. Sustained levels of high inflation have likewise caused the U. S. Federal Reserve and other central banks to increase interest rates, which could have the effects of raising the cost of capital and depressing economic growth, either of which, or the combination thereof, could hurt the financial and operating results of our operators' businesses. If our operators are unable to secure the goods, services and labor necessary for their operations at reasonable costs, their exploration and development activities could be delayed or restricted, which in turn could have a material adverse effect on our financial condition, results of operations and free cash flow. Regulatory and Environmental Risk Factors Environmental costs and liabilities and changing environmental regulation could affect our cash flow. As with other companies engaged in the ownership and production of oil and natural gas, we always have possible risk of exposure to environmental costs and liabilities because of the costs associated with environmental compliance or remediation. The properties in which we hold interests are subject to extensive federal, state, tribal and local regulatory requirements relating to environmental affairs, health and safety and waste management. Governmental authorities have the power to enforce compliance with applicable regulations and permits, which could increase production costs on our properties and affect their cash flow. Third parties may also have the right to pursue legal actions to enforce compliance. Because we do not directly operate our properties, our direct liability under environmental laws is limited. It is likely, however, that expenditures in connection with environmental matters, individually or as part of normal capital expenditure programs, will affect the net cash flow from our properties. Future environmental law developments, such as stricter laws, regulations or enforcement policies, could significantly increase the costs of production from our properties and reduce our cash flow. The following is a summary of some of the existing environmental laws, rules and regulations that apply to oil and natural gas operations, and that may indirectly affect our cash flow. The Comprehensive Environmental Response, Compensation and Liability Act (" CERCLA "), also known as the Superfund law, and comparable state statutes impose strict liability (i. e., no showing of " fault " is required), and under certain circumstances, joint and several liability, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. The term " hazardous substance " is specifically defined to exclude petroleum, including crude oil and any fraction thereof, natural gas and natural gas liquids. Despite this exclusion, certain materials that are commonly used in connection with oil and natural gas operations are considered to be hazardous substances under CERCLA. Responsible persons include the current or former owner or operator of the site where the release occurred, and anyone who disposed of or arranged for the disposal of a hazardous substance released at the site, regardless of whether the disposal of hazardous substances was lawful at the time of the disposal. Under CERCLA, such persons may be subject to strict, joint and several liabilities for the costs of investigating releases of hazardous substances, cleaning up the hazardous substances that have been released into the environment, damages to natural resources and certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The operators of our properties may be responsible under CERCLA for all or part of these costs. Although we are not an operator, our ownership of royalty interests could cause us to be responsible for all or part of such costs to the extent that CERCLA imposes such responsibilities on such parties as " owners. " 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. Drilling fluids, produced water and many other wastes associated with the exploration, development and production of oil or natural gas are currently excluded from regulation under RCRA' s hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes could be classified as hazardous wastes in the future. In addition, exploration and production wastes are regulated under state laws analogous to RCRA. Many of our properties have produced oil and / or natural gas for many years. We have no knowledge of current and prior operators' procedures with respect to the disposal of oil and natural gas wastes. Hydrocarbons or other solid or hazardous wastes may have been released on or under our properties by the operators or prior operators. Our properties and the materials disposed or released on, at, under or from them may be subject to CERCLA, RCRA and analogous state laws, and removal or remediation of such materials could be required by a governmental authority. The Federal Clean Air Act (" CAA ") and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and other requirements, such as emissions controls. Existing laws and regulations and possible future laws and regulations may require our operators to obtain pre- approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions and may impose stringent air permit requirements or mandate the use of specific equipment or technologies to control emissions. The U. S. Environmental Protection Agency (" EPA ") continues to develop New Source Performance standards for oil and natural gas facilities. On May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, on August 13, 2020, in response to an executive order by ~~former~~ President Trump, the EPA amended the New Source Performance standards to ease regulatory burdens, including rescinding standards applicable to transmission or storage segments and eliminating methane requirements altogether. On June 30, 2021, President Biden signed into law a joint resolution of Congress disapproving the 2020 amendments, with the exception of some technical changes, thereby reinstating the prior standards. The EPA expects owners and operators of regulated sources to take " immediate steps " to comply with these standards. Additionally, on ~~December 2~~ **March 8** , ~~2023~~ **2024** , the EPA ~~announced~~ **published** a final rule that would expand and strengthen emission reduction requirements for both new and existing sources in the oil and natural gas industry by requiring increased monitoring of fugitive emissions, imposing new requirements for pneumatic controllers and tank batteries, and prohibiting venting of natural gas in certain situations ~~. Additionally, on April 17, 2023, the EPA agreed in a consent decree to issue a proposed rule by December 10, 2024 that either revises its emission standards for hazardous air pollutants from oil and natural gas production activities or determines that no revision is necessary~~ . Federal changes will affect state air permitting programs in states that administer the federal CAA under a delegation of authority, including states in which we have operations. These new standards, to the extent implemented, as well as any future laws and their implementing regulations, may require our operators to obtain pre- approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions. We cannot predict the final regulatory requirements or the cost to our operators to comply with such requirements with any certainty. The Federal Water Pollution Control Act (the " Clean Water Act " or " CWA ") and analogous state laws impose restrictions and strict controls on the discharge of pollutants and fill material, including spills and leaks of oil and other substances into regulated waters, including wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, an analogous state agency, or, in the case of fill material, the United States Army Corps of Engineers (" USACOE ") **. The scope of waters regulated under the CWA has fluctuated in recent years** . On June 29, 2015, the EPA and the USACOE jointly promulgated a final rule expanding the scope of " Waters of the United States " (" WOTUS "), which would have made additional waters subject to the jurisdiction of the Clean Water Act. However, on October 22, 2019, the agencies published a final rule to repeal the 2015 WOTUS rule, and then, on April 21, 2020, the EPA and the USACOE published a final rule replacing the 2015 rule and significantly reducing the waters subject to federal regulation under the CWA. On August 30, 2021, a federal court struck down the replacement rule and, on January 18, 2023, the

EPA and the USACOE published a final rule that would restore water protections that were in place prior to 2015. However, on May 25, 2023, the Supreme Court issued an opinion substantially narrowing the scope of " waters of the United States " protected under the CWA. On September 8, 2023, the EPA and the USACOE published a final rule conforming their regulations to the decision. These recent actions have provided some clarity. To the extent the EPA and the USACOE broadly interpret their jurisdiction and expand the range of properties subject to the CWA' s jurisdiction, our operators could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas, which could cause delays in development and / or increase the cost of development and operation of those properties. Spill prevention, control, and countermeasure (" SPCC ") regulations promulgated under the CWA and later amended by the Oil Pollution Act of 1990 impose obligations and liabilities related to the prevention of oil spills and damages resulting from such spills into or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities that store oil in more than threshold quantities, the release of which could reasonably be expected to reach jurisdictional waters, must develop, implement, and maintain SPCC Plans. 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 EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Various federal laws, including the Endangered Species Act and the Migratory Bird Treaty Act, and analogous state laws, restrict activities that may adversely affect listed endangered or threatened species or their habitat. If endangered or threatened species are located on our properties, operations on those properties could be prohibited or delayed or expensive mitigation may be required. Also, the United States Fish and Wildlife Service (" USFWS ") may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access, development or operations (including prevent oil and natural gas exploration or production). Additionally, the designation of previously unprotected species in areas where we operate as endangered or threatened could result in the imposition of restrictions on our operators and consequently have a material adverse effect on our business. Oil and natural gas operations are subject to the requirements of the federal Occupational Safety and Health Act (" OSHA ") and comparable state statutes and their implementing regulations. The OSHA hazard communication standard, the EPA community right- to- know regulations under Title III of CERCLA, the general duty clause and Risk Management Planning regulations promulgated under section 112 (r) of the CAA and similar state statutes may require disclosure of information about hazardous materials used, produced or otherwise managed during operation. These laws also require the development of risk management plans for certain facilities to prevent accidental releases of extremely hazardous substances and to minimize the consequences of such releases should they occur. The potential adoption of federal and state hydraulic fracturing laws or executive orders could delay or restrict development of our oil and natural gas properties. Hydraulic fracturing is an important, common practice that is used to stimulate production of hydrocarbons from tight formations, including shales. The process, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act (" SDWA ") to repeal the exemption for hydraulic fracturing from the definition of " underground injection, " to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as " Class II " Underground Injection Control wells under the SDWA. Future federal laws or regulations could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations and meet plugging and abandonment requirements. Such federal legislation or regulation could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing. In addition, on March 26, 2015, the Bureau of Land Management (" BLM ") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. Also, on November 18, 2016, the BLM finalized a rule to reduce the flaring, venting and leaking of methane from oil and natural gas operations on federal and Indian lands. On March 28, 2017, ~~former~~ President Trump signed an executive order directing the BLM to review the above rules and, if appropriate, to initiate a rulemaking to rescind or revise them. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule. A coalition of environmentalists, tribal advocates and the State of California filed lawsuits challenging the rule rescission. Also, on September 28, 2018, the BLM published a final rule to revise the 2016 methane rule; however, a federal court struck down the scaled- back rule on July 15, 2020, and shortly thereafter, on October 8, 2020, another federal court struck down the 2016 methane rule. On ~~November 28~~ **April 10** , ~~2022~~ **2024** , the BLM ~~announced~~ **published** a ~~proposed~~ **final** replacement rule to reduce the waste of natural gas from venting, flaring and leaks during oil and **natural** gas production activities on federal and Indian lands, which would require the use of upgraded equipment in some cases and would place time and volume limits on royalty- free flaring. **On April 24, 2024, several states challenged the 2024 waste**

**prevention rule in federal court, which has resulted in a preliminary injunction against the BLM enforcing the rule in North Dakota, Texas, Montana, Wyoming, and Utah.** Also, on ~~July 24~~ **April 23** , ~~2023~~ **2024** , the BLM published a ~~proposed~~ **final** rule to update its oil and gas leasing regulations, which ~~would increase~~ **increases** bonding requirements and ~~raise~~ **raises** royalty rates ~~. At this time, it is uncertain when, or if, the above rules will be implemented or if new requirements will be adopted~~ . Each of these regulations, to the extent that they are **implemented,** reinstated or modified, may result in additional levels of regulation or complexity that could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase costs of compliance. Additionally, certain states in which our properties are located, including Oklahoma, Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic- fracturing operations or otherwise seek to ban fracturing activities altogether. For example, pursuant to legislation adopted by the State of Texas in June 2011, the Railroad Commission of Texas enacted a rule in December 2011, requiring public disclosure of certain information regarding additives, chemical ingredients, concentrations and water volumes used in hydraulic fracturing. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit well drilling in general and / or hydraulic fracturing in particular. In response to a 2014 ballot initiative by the voters of the City of Denton, Texas banning hydraulic fracturing, the Texas legislature enacted a statute preempting local government regulation of oil and natural gas activities, including hydraulic fracturing. In other states, however, local governments may retain the ability to directly or indirectly regulate hydraulic fracturing. State and local governments may also seek to regulate or recover costs of activities tangentially associated with hydraulic fracturing, such as increased truck traffic. In the event state, local, or municipal legal restrictions are adopted in areas where our properties are located, the cost of the operators of our oil and natural gas properties to comply with such requirements may be significant in nature, which may cause delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even preclude the operators from drilling wells. Some states have become concerned about the connection between hydraulic fracturing- related activities, particularly the injection or disposal of produced water, and the increased occurrence of seismic activity, and they have adopted or are considering additional regulations regarding such activities. Changes in regulations or the inability to obtain permits for new disposal wells in the future may affect the ability of the operators of the Royalty Properties and the operators of the working interests and other properties underlying our NPIs to dispose of produced water and ultimately increase the cost of operation of the Royalty Properties and the working interests and other properties underlying our NPIs or delay production schedules. Certain state agencies, including those in Texas and Oklahoma, have implemented regulations authorizing the imposition of certain limitations on existing wells if seismic activity increases in the area of an injection well, including a temporary injection ban. For example, in Oklahoma, the Oklahoma Corporations Commission (“ OCC ”) has implemented a variety of measures, including the adoption of the National Academy of Science’ s “ traffic light system, ” pursuant to which the agency reviews new disposal well applications and may restrict operations at existing wells. Beginning in 2013, the OCC has ordered the reduction of disposal volumes into the Arbuckle formation. More recently, the OCC directed the shut in of a number of disposal wells due to increased earthquake activity in the Arbuckle formation and imposed further disposal well volume reductions in the Covington, Crescent, Enid, and Edmond areas. The Texas Railroad Commission has also implemented measures to assess the potential for seismic activity in the vicinity of disposal wells, and it has restricted and indefinitely suspended disposal well activities in some cases. Moreover, vigorous public debate over hydraulic fracturing and shale gas production continues and has resulted in delays of well permits in some areas. Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies have also evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for our operators to perform fracturing and increase their costs of compliance and doing business. ~~The adoption of climate~~ **Climate** change legislation or regulations could result in increased operating costs and reduced demand for the oil and natural gas production from our properties. In recent years, federal, state, and local governments have taken steps to reduce emissions of greenhouse gases (“ GHGs ”) **, though policy changes at the federal level have caused uncertainty** . For example, the Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022 (“ IRA ”) include billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles, investments in advanced biofuels and supporting infrastructure and carbon capture and sequestration. ~~The~~ **Also, in March 2024, the** EPA **finalized** ~~has proposed~~ ambitious rules to reduce harmful air pollutant emissions, including GHGs, from light-, medium-, and heavy- duty vehicles beginning in model year 2027 ~~. These incentives and regulations could accelerate the transition of the economy away from the use of fossil fuels towards lower or zero- carbon emissions alternatives~~ , which could decrease demand for, and in turn the prices of, oil and natural gas and adversely impact our business. In addition, the IRA imposes the first ever federal fee on the emission of GHGs through a methane emissions charge. Specifically, the IRA amends the Clean Air Act to impose a fee on the emission of methane that exceeds an applicable waste emissions threshold from sources required to report their GHG emissions to the EPA, including sources in the offshore and onshore petroleum and natural gas production and gathering and boosting source categories. **In** ~~The methane emissions charge would start in calendar year 2024 at $ 900 per ton of methane, increase to $ 1, 200 in 2025 and be set at $ 1, 500 for 2026 and each year after. Calculation of the fee is based on certain thresholds established in the IRA. On January 12, 2024, the EPA announced a proposed rule to implement~~ **implemented ,** ~~the methane emissions charge. The~~ methane emissions charge could increase our operators’ costs, which could adversely impact our business, financial condition and cash flows **. However, on January 20, 2025, President Trump signed multiple executive orders seeking to reverse these climate incentives, including pausing the disbursement of funds under the IRA. The same day, President Trump also issued executive orders to encourage fossil fuel production and exploration on federal lands and waters, while moving away from renewable energy and electric vehicles. Such actions have the potential to impact prior efforts to transition the economy away from the use of fossil fuels and towards lower or zero- carbon emissions alternatives** . The EPA has also finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and almost half of the states have taken measures to reduce GHG emissions primarily through the development of GHG emission inventories and / or regional GHG cap and trade programs. The cap and trade programs require major sources of emissions or major fuel producers to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Many states also have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources. In addition, states have imposed increasingly stringent requirements related to the venting or flaring of natural gas during oil and natural gas operations. ~~In addition~~ **At the international level** , the United States has been involved in ~~international~~ negotiations regarding GHG reductions under the United Nations Framework Convention on Climate Change (" UNFCCC "). The U. S. was among approximately 195 nations that signed an international accord in December 2015, the so called Paris Agreement, which became effective on November 4, 2016, with the objective of limiting GHG emissions. On April 21, 2021, the United States announced that it was setting an economy- wide target of reducing its GHG emissions by 50- 52 percent below 2005 levels by 2030. In November 2021, in connection with Glasgow Climate Pact, the United States and other world leaders made further commitments to reduce GHG emissions, including reducing global methane emissions by at least 30 ~~%~~ **percent** by 2030 from 2020 levels. More than 150 countries have now signed on to this pledge. Most recently, at the 28th Conference of the Parties in the United Arab Emirates, world leaders agreed to transition away from fossil fuels in a just, orderly and equitable manner and to triple renewables and double energy efficiency globally by 2030. **Additionally, the Biden Administration announced a new climate target for the United States on December 19, 2024, which included a 61- 66 percent reduction in economy- wide net greenhouse gas emissions by 2035, as compared to 2005 levels.** Many state and local leaders have stated their intent to intensify efforts to support the international climate commitments. ~~Although~~ **Though President Trump issued an executive order on January 20, 2025, directing** ~~these~~ -- **the United States Ambassador to the United Nations to immediately withdraw from the Paris Agreement, it is possible that the Paris Agreement and other domestic and** international ~~commitments are not directly binding on companies, additional GHG reduction~~ regulatory requirements **will have** ~~may be issued in~~ an **adverse effect on** ~~effort to help meet~~ the **demand for oil and natural gas products** ~~U. S. commitments under the Paris Agreement~~ . Although it is not possible at this time to predict whether or when Congress may adopt additional climate change legislation, or whether EPA may promulgate additional regulation of GHGs from the oil and natural gas industry, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require oil and natural gas operators that develop our properties to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas produced from our properties. It should also be noted that, recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil fuel 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. In addition, spurred by increasing concerns regarding climate change, the oil and natural gas industry faces growing demand for corporate transparency and a demonstrated commitment to sustainability goals. Environmental, social, and governance (" ESG ") goals and programs, which typically include extralegal targets related to environmental stewardship, social responsibility, and corporate governance, have become an increasing focus of investors and shareholders across the industry. While reporting on ESG metrics remains voluntary, access to capital and investors is likely to favor companies with robust ESG programs in place. ~~In~~ **The SEC published final rules on** March **28,** ~~2022~~ **2024** , ~~the SEC proposed new rules~~ relating to the disclosure of a range of climate- related risks and other information. **Several lawsuits have been filed challenging the rules. In April 2024, the SEC agreed to pause the rules to facilitate an orderly judicial resolution.** To the extent ~~this~~ **the** ~~rule~~ **rules are implemented** ~~is finalized as proposed~~ , the Partnership, our operators and / or our customers could incur increased costs related to the assessment and disclosure of climate- related information. Enhanced climate disclosure requirements could also accelerate any trend by certain stakeholders and capital providers to restrict or seek more stringent conditions with respect to their financing of certain carbon intensive sectors. Ultimately, these initiatives could make it more difficult to secure funding for exploration and production activities. Finally, climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our operators' activities and increase their costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations. Our oil and natural gas reserve data and future net revenue estimates are uncertain. Estimates of proved reserves and related future net revenues are projections based on engineering data and reports of independent consulting petroleum engineers hired for that purpose. The process of estimating reserves requires substantial judgment, resulting in imprecise determinations. Different reserve engineers may make different estimates of reserve quantities and related revenue based on the same data. Therefore, those estimates should not be construed as being accurate estimates of the current market value of our proved reserves. If these estimates prove to be inaccurate, our business may be adversely affected by lower revenues. We are affected by changes in oil and natural gas prices. Oil prices and natural gas prices may experience inverse price changes. The outcome of pending litigation related to the Dakota Access

Pipeline and any related executive orders could have a material adverse effect on our revenue and cash distributions. In connection with ongoing litigation initiated in February 2017 by the Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe contesting the validity of the process used by the USACOE to permit the Dakota Access Pipeline, on July 6, 2020, the United States District Court for the District of Columbia (the " Court ") issued an order vacating the USACOE' s easement for the Dakota Access Pipeline and requiring that the pipeline be shut down by August 5, 2020. Dakota Access, LLC and the USACOE appealed the decision. On July 14, 2020, the Court of Appeals granted a temporary administrative stay, and on January 26, 2021, the Court of Appeals affirmed that part of the lower court decision vacating the USACOE' s easement while it prepares a new environmental impact statement, but reversed the lower court' s order to shut down the pipeline. Since then, both the Biden Administration and the Court have declined to shut down the pipeline, and on June 22, 2021, the Court dismissed the subject lawsuit. The Court noted, however, that future challenges were possible depending on the outcome of the ongoing environmental study, which the USACOE issued in draft form on September 8, 2023 **. On October 14, 2024, the Standing Rock Sioux Tribe filed a new lawsuit in the U. S. District Court for the District of Columbia, alleging that the USACOE is allowing the pipeline to operate without the necessary easement and without an appropriate environmental impact statement. The USACOE and Dakota Access Pipeline filed motions to dismiss the case on January 17, 2025, though the matter remains pending** . Accordingly, the continued operation of Dakota Access Pipeline in the future is uncertain. While this litigation does not directly impact our operations, we derive a significant amount of revenue from the Royalty Properties and NPIs we hold in the Bakken region, the region for which the Dakota Access Pipeline is intended to be a key pipeline. The outcome of this litigation may have a material adverse effect on our Royalty and NPI revenues derived from the Bakken region based on the timing of future development of wells on, or production of oil and natural gas from, or the method and cost of transportation related to the production on the properties. We have no control over the operation of such properties. Risks Inherent In An Investment In Our Common Units Cost reimbursement due our General Partner may be substantial and reduce our cash available to distribute to our unitholders. Prior to making any distribution on the common units, we reimburse the General Partner and its affiliates for reasonable costs and expenses of management. The reimbursement of expenses could adversely affect our ability to pay cash distributions to our unitholders. Our General Partner has sole discretion to determine the amount of these expenses, subject to the annual limit of 5 % of an amount primarily based on our distributions to partners for that fiscal year. The annual limit includes carry- forward and carry- back features, which could allow costs in a year to exceed what would otherwise be the annual reimbursement limit. In addition, our General Partner and its affiliates may provide us with other services for which we will be charged fees as determined by our General Partner. Our net income as reported for tax and financial statement purposes may differ significantly from our cash flow that is used to determine cash available for distributions. Net income as reported for financial statement purposes is presented on an accrual basis in conformity with accounting principles generally accepted in the United States of America. Unitholder Schedule K- 1 tax statements are calculated based on applicable tax conventions, and taxable income as calculated for each year will be allocated among unitholders who hold units on the last day of each month. Distributions, however, are calculated on the basis of actual cash receipts, changes in cash reserves, and disbursements during the relevant reporting period. Consequently, due to timing differences between the receipt of proceeds of production and the point in time at which the production giving rise to those proceeds actually occurs, net income reported on our consolidated financial statements and on unitholder Schedule K- 1 tax statements will not reflect actual cash distributions during that reporting period. Our unitholders have limited voting rights and do not control our General Partner, and their ability to remove our General Partner is limited. Our unitholders have only limited voting rights on matters affecting our business. The general partner of our General Partner manages our activities. Our unitholders only have the right to annually elect the managers comprising the Advisory Committee of the Board of Managers of the general partner of our General Partner. Our unitholders do not have the right to elect the other managers of the general partner of our General Partner on an annual or any other basis. Our General Partner may not be removed as our general partner except upon approval by the affirmative vote of the holders of at least a majority of our outstanding common units (including common units owned by our General Partner and its affiliates), subject to the satisfaction of certain conditions. Our General Partner and its affiliates do not own sufficient common units to be able to prevent its removal as general partner, but they do own sufficient common units to make the removal of our General Partner by other unitholders difficult. These provisions may discourage a person or group from attempting to remove our General Partner or acquire control of us without the consent of our General Partner. As a result of these provisions, the price at which our common units trade may be lower because of the absence or reduction of a takeover premium in the trading price. The control of our General Partner may be transferred to a third party without unitholder consent. Our General Partner may withdraw or transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Other than some transfer restrictions agreed to among the owners of our General Partner relating to their interests in our General Partner, there is no restriction in our partnership agreement or otherwise for the benefit of our limited partners on the ability of the owners of our General Partner to transfer their ownership interests to a third party. The new owner of the General Partner would then be in a position to replace the management of our Partnership with its own choices. **A group of unitholders own a large percentage of our units and have the right to appoint a Manager to our Board of Managers and may be able to exert significant influence over certain matters. West Texas Minerals LLC and Carrollton Mineral Partners, LP, and certain affiliates, beneficially hold, in the aggregate, approximately 6. 9 % of our outstanding Units. These unitholders, acting together, would be able to influence all matters requiring unitholder approval and have the right to appoint a Manager to our Board of Managers, for so long as they collectively hold an aggregate of at least 1, 000, 000 Units. For example, these unitholders would be able to influence amendments of our organizational documents, or approval of any merger, sale of assets, or other major corporate transaction.** Our General Partner and its affiliates have conflicts of interests, which may permit our General Partner and its affiliates to favor their own interests to the detriment of unitholders. We and our General Partner and its affiliates share, and therefore compete for, the time and effort of General Partner personnel who provide services to us. Officers of our General Partner and its affiliates do not, and are not required to, spend any specified percentage or amount of time on our business. In fact, our General Partner has a duty to manage our Partnership in the best interests of our unitholders, but it also has a duty to operate its business for the benefit of its partners. Some of our officers are also involved in management and ownership roles in other oil and natural gas enterprises and have similar duties to them and devote time to their businesses. Because these shared officers function as both our representatives and those of our General Partner and its affiliates and of third parties, conflicts of interest could arise between our General Partner and its affiliates, on the one hand, and us or our unitholders, on the other, or between us or our unitholders on the one hand and the third parties for which our officers also serve management functions. As a result of these conflicts, our General Partner and its affiliates may favor their own interests over the interests of unitholders. We may issue additional securities, diluting our unitholders' interests. We can and may issue additional common units and other capital securities representing limited partnership units, including options, warrants, rights, appreciation rights and securities with rights to distributions and allocations or in liquidation equal or superior to our common units; however, a majority of the unitholders must approve such issuance if (i) the partnership securities to be issued will have greater rights or powers than our common units or (ii) if after giving effect to such issuance, such newly issued partnership securities represent over 40 % of the outstanding limited partnership interests. If we issue additional common units, it will reduce our unitholders' proportionate ownership interest in us. This could cause the market price of the common units to fall and reduce the per unit cash distributions paid to our unitholders. In addition, if we issued limited partnership units with voting rights superior to the common units, it could adversely affect our unitholders' voting power. Our unitholders may not have limited liability in the circumstances described below and may be liable for the return of certain distributions. Under Delaware law, our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our General Partner or to take other action under our partnership agreement constituted participation in the" control" of our business. Our General Partner generally has unlimited liability for the obligations of our Partnership, such as its debts and environmental liabilities, except for those contractual obligations of our Partnership that are expressly made without recourse to the General Partner. In addition, Section 17- 607 of the Delaware Revised Uniform Limited Partnership Act provides that, under certain circumstances, a unitholder may be liable for the amount of distribution for a period of three years from the date of distribution. Because we conduct our business in various states, the laws of those states may pose similar risks to our unitholders. To the extent to which we conduct business in any state, our unitholders might be held liable for our obligations as if they were general partners if a court or government agency determined that we had not complied with that state' s partnership statute, or if rights of unitholders constituted participation in the" control" of our business under that state' s partnership statute. In some of the states in which we conduct business, the limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established. We are dependent upon key personnel, and the loss of services of any of our key personnel could adversely affect our operations. Our continued success depends to a considerable extent upon the abilities and efforts of the senior management of our General Partner, particularly William Casey McManemin, its Chief Executive Officer, and our Chief Executive Officer, Bradley J. Ehrman, and Chief Financial Officer, Leslie A. Moriyama. The loss of the services of any of these key personnel could have a material adverse effect on the results of our operations. We have not obtained insurance or entered into employment agreements with any of these key personnel. We are dependent on service providers who assist us with providing Schedule K- 1 tax statements to our unitholders. There are a very limited number of service firms that currently perform the detailed computations needed to provide each unitholder with estimated depletion and other tax information to assist the unitholder in various U. S. federal income tax computations. There are also very few publicly traded limited partnerships that need these services. As a result, the future costs and timeliness of providing Schedule K- 1 tax statements to our unitholders is uncertain. Tax Risk Factors The tax consequences to a unitholder of the ownership and sale of common units will depend in part on the unitholder’ s tax circumstances. Each unitholder should consult such unitholder’ s own tax advisor about the federal, state and local tax consequences of the ownership of common units. We generally do not obtain rulings or assurances from the IRS or state or local taxing authorities on matters affecting us. We generally have not requested, and do not intend to request, rulings from the Internal Revenue Service, or IRS, or state or local taxing authorities with respect to owning and disposing of our common units or other matters affecting us. It may be necessary to resort to administrative or court proceedings in an effort to sustain some or all of those conclusions or positions taken or expressed by us, and some or all of those conclusions or positions ultimately may not be sustained. Our unitholders and General Partner will bear, directly or indirectly, the costs of any contest with the IRS or other taxing authority. In 2020, we obtained a ruling from the IRS permitting us to aggregate the Minerals NPI, including the previously aggregated Maecenas NPI, Bradley NPI, Republic NPI, and Spinnaker NPI for federal income tax purposes effective January 1, 2020. We will be subject to federal income tax and possibly certain state corporate income or franchise taxes if we are classified as a corporation and not as a partnership for federal income tax purposes. 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 would be treated as a corporation for U. S. federal income tax purposes unless we satisfy a" qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. A change in our business or a change in current law could cause us to be treated as a corporation for U. S. federal income tax purposes or otherwise subject us to taxation as an entity. 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, which is currently a maximum of 21 %, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. In addition, changes in current state law may subject us to additional entity- level taxation by individual states. Several states have subjected, or are evaluating ways to subject, partnerships to entity- level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders. Therefore, treatment of us as a corporation or the assessment of a material amount of entity- level taxation would result in a material reduction in the anticipated cash flow and after- tax return to our unitholders, likely causing a substantial 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 or differing interpretations, possibly applied on a retroactive basis. The present U. S. 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 changes or differing interpretations at any time. For example, from time to time, the President and members of Congress propose and consider substantive changes to the existing U. S. federal income tax laws that affect publicly traded partnerships, including elimination of partnership tax treatment for publicly traded partnerships. Under current law, we believe that our royalty income is qualifying income for purposes of Section 7704 (d) (1) (E) of the Internal Revenue Code **of 1986, as amended** (the " Code "). If the current law remains effective in its current form, we believe we will continue to be able to meet the qualifying income requirement. However, there can be no assurance that there will not be changes to the federal income tax laws or the Treasury Department' s interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership for federal income tax purposes in the future. 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 for us to be treated as a partnership for federal income tax purposes or otherwise adversely affect us. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. The recently enacted 20 % deduction for certain pass-through income may not be available for our unitholders' allocable share of our net income, in which case our unitholders' tax liability with respect to ownership and disposition of our units may be materially higher than if the deduction is available. For taxable years beginning after December 31, 2017 and ending on or before December 31, 2025, an individual taxpayer may generally claim a deduction in the amount of 20 % of its allocable share of certain publicly traded partnership income, including generally, among other items, the net amount of its items of income, gain, deduction, and loss from a publicly traded partnership' s U. S. trade or business. Because we own only non- operated, passive mineral and royalty interests, most or all of the income that we now generate, or will generate in the future, may not be " qualifying publicly traded partnership income " eligible for the 20 % deduction. If the deduction is not available, our unitholders' tax liability from ownership and disposition of our units may be materially higher than if the deduction is available. We urge our unitholders to consult with their tax advisors regarding the availability of the 20 % deduction on any income allocated from us. The IRS could reallocate items of income, gain, deduction and loss between transferors and transferees of common units if the IRS does not accept our monthly convention for allocating such items. In general, each of our items of income, gain, loss and deduction will, for federal income tax purposes, be determined annually, and one twelfth of each annual amount will be allocated to those unitholders who hold common units on the last business day of each month in that year. In certain circumstances we may make these allocations in connection with extraordinary or nonrecurring events on a more frequent basis. As a result, transferees of our common units may be allocated items of our income, gain, loss and deduction realized by us prior to the date of their acquisition of our common units. The U. S. Treasury Department has issued final Treasury regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferors and transferee unitholders. Nonetheless, if the IRS challenges our method of allocation, our income, gain, loss and deduction may be reallocated among our unitholders and our General Partner, and our unitholders may have more taxable income or less taxable loss. Our General Partner is authorized to revise our method of allocation between transferors and transferees, as well as among our other unitholders whose common units otherwise vary during a taxable period, to conform to a method permitted or required by the Code and the regulations or rulings promulgated thereunder. Our unitholders may not be able to deduct losses attributable to their common units. Any losses relating to our unitholders' common units will be losses related to portfolio income and their ability to use such losses may be limited. Our unitholders' partnership tax information may be audited. We will furnish our unitholders with a Schedule K- 1 tax statement that sets forth their allocable share of income, gains, losses and deductions. In preparing this schedule, we will use various accounting and reporting conventions and various depreciation and amortization methods we have adopted. This schedule may not yield a result that conforms to statutory or regulatory requirements or to administrative pronouncements of the IRS. Further, our tax return may be audited, and any such audit could result in an audit of our unitholders' individual income tax returns as well as increased liabilities for taxes because of adjustments resulting from the audit. An audit of our unitholders' returns also could be triggered if the tax information relating to their common units is not consistent with the Schedule K- 1 that we are required to provide to the IRS. Our unitholders may have more taxable income or less taxable loss with respect to their common units if the IRS does not respect our method for determining the adjusted tax basis of their common units. We have adopted a reporting convention that will enable our unitholders to track the basis of their individual common units or unit groups and use this basis in calculating their basis adjustments under Section 743 of the Code and gain or loss on the sale of common units. This method does not comply with an IRS ruling that requires a portion of the combined tax basis of all common units to be allocated to each of the common units owned by a unitholder upon a sale or disposition of less than all of the common units and may be challenged by the IRS. If such a challenge is successful, our unitholders may recognize more taxable income or less taxable loss with respect to common units disposed of and common units they continue to hold. Tax- exempt investors may recognize unrelated business taxable income. Generally, unrelated business taxable income, or UBTI, can arise from a trade or business unrelated to the exempt purposes of the tax- exempt entity that is regularly carried on by either the tax- exempt entity or a partnership in which the tax- exempt entity is a partner. However, UBTI does not apply to interest income, royalties (including overriding royalties) or net profits interests, whether the royalties or net profits are measured by production or by gross or taxable income from the property. Pursuant to the provisions of our partnership agreement, our General Partner shall use all reasonable efforts to prevent us from realizing income that would constitute UBTI. In addition, our General Partner is prohibited from incurring certain types and amounts of indebtedness and from directly owning working interests or cost bearing interests and, in the event that any of our assets become working interests or cost bearing interests, is required to assign such interests to the Operating Partnership subject to the reservation of a net profits overriding royalty interest. However, it is possible that we may realize income that would constitute UBTI in an effort to maximize unitholder value. Tax consequences of certain NPIs are uncertain. We are prohibited from owning working interests or cost- bearing interests. At the time of the creation of the Minerals NPI, we assigned to the Operating Partnership all rights in any such working interests or cost- bearing interests that might subsequently be created from the mineral properties that were and are subject of the Minerals NPI. As additional working interests and other cost- bearing interests are created out of such mineral properties, they are owned by the Operating Partnership pursuant to such original assignment, and we have executed various documents since the creation of the Minerals NPI to confirm such treatment under the original assignment. This treatment could be characterized differently by the IRS, and in such a case we are unable to predict, with certainty, all of the income tax consequences relating to the Minerals NPI as it relates to such working interests and other cost- bearing interests. Our unitholders may not be entitled to deductions for percentage depletion with respect to our oil and natural gas interests. Our unitholders will be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to the oil and natural gas interests owned by us. However, percentage depletion is generally available to a unitholder only if the unitholder qualifies under the independent producer exemption contained in the Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, natural gas, or derivative products or the operation of a major refinery. If a unitholder does not qualify under the independent producer exemption, the unitholder generally will be restricted to deductions based on cost depletion. Our unitholders may have more taxable income or less taxable loss on an ongoing basis if the IRS does not accept our method of allocating depletion deductions. The Code requires that income, gain, loss and deduction attributable to appreciated or depreciated property that is contributed to a partnership in exchange for a partnership interest be allocated so that the contributing partner is charged with, or benefits from, unrealized gain or unrealized loss, referred to as “ Built- in Gain ” and “ Built- in Loss, ” respectively, associated with the property at the time of its contribution to the partnership. Our partnership agreement provides that the adjusted tax basis of the oil and natural gas properties contributed to us generally is allocated to the contributing partners for the purpose of separately determining depletion deductions. Any gain or loss resulting from the sale of property contributed to us generally will be allocated to the partners that contributed the property, in proportion to their percentage interest in the contributed property, to take into account any Built- in Gain or Built- in Loss. This method of allocating Built- in Gain and Built- in Loss is not specifically permitted by the applicable Treasury regulations, and the IRS may challenge this method. Such a challenge, if successful, could cause our unitholders to recognize more taxable income or less taxable loss on an ongoing basis in respect of their common units. Our unitholders may have more taxable income or less taxable loss on an ongoing basis if the IRS does not accept our method of determining a unitholder' s share of the basis of partnership property. Our General Partner utilizes a method of calculating each unitholder' s share of the basis of partnership property that results in an aggregate basis for depletion purposes that reflects the purchase price of common units as paid by the unitholder. This method is not specifically authorized under applicable Treasury regulations, and the IRS may challenge this method. Such a challenge, if successful, could cause our unitholders to recognize more taxable income or less taxable loss on an ongoing basis in respect of their common units. The ratio of the amount of taxable income that will be allocated to a unitholder to the amount of cash that will be distributed to a unitholder is uncertain, and cash distributed to a unitholder may not be sufficient to pay tax on the income we allocate to a unitholder. The amount of taxable income realized by a unitholder will be dependent upon a number of factors, and so we cannot predict the ratio of the amount of taxable income that will be allocated to a unitholder to the amount of cash that will be distributed to a unitholder. Unitholders will be required to pay U. S. federal income taxes and, in some cases, state and local income taxes, on their share of taxable income, whether or not they receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income. A unitholder may lose his status as a partner of our Partnership for federal income tax purposes if the unitholder lends our common units to a short seller to cover a short sale of such common units. If a unitholder loans his common units to a short seller to cover a short sale of common units, the unitholder may be considered as having disposed of his ownership of those common units for federal income tax purposes. If so, the unitholder would no longer be a partner of our Partnership for tax purposes with respect to those common 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 common units would not be reportable, and any cash distributions received for those common units would be fully taxable and may be treated as ordinary income. Foreign, state and local taxes could be withheld on amounts otherwise distributable to a unitholder. A unitholder may be required to file tax returns and be subject to tax liability in the foreign, state or local jurisdictions where the unitholder resides and in each state or local jurisdiction in which we have assets or otherwise do business. We also may be required to withhold state income tax from distributions otherwise payable to a unitholder, and state income tax may be withheld by others on royalty payments to us. If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced. If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We generally will have the ability to shift any such tax liability (including any applicable penalties and interest) to our General Partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so under all circumstances. If we are unable to have our 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 economic burden resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced. Our unitholders may be subject to withholding tax upon transfers of their common units. If a unitholder sells or otherwise disposes of a common unit on or after January 1, 2023, the transferee generally will be required to withhold 10 % of the amount realized by the transferor unless the transferor certifies that it is not a foreign person. However, final regulations issued by the Treasury Department on the application of these rules to transfers of certain publicly traded partnership interests, including our common units, provide that the obligation to withhold on a transfer of interests in a publicly traded partnership that is effected through a broker is imposed on the transferor' s broker (instead of the transferee), and the " amount realized " on such a transfer will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor (and thus determined without regard to any decrease in that transferor' s share of the publicly traded partnership' s liabilities). Prospective foreign unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units. General Risk Factors Public health threats could have an adverse effect on our Partnership, our cash flow and our industry. Public health threats and other highly communicable diseases, outbreaks of which have been occurring in across the world, including the United States, could adversely impact our Partnership, drilling activities on our properties and the global economy. In particular, the outbreak starting in 2020 of a coronavirus (COVID- 19) resulted in quarantines, restrictions on travel and a decrease in economic activity across the world, which then resulted in a decrease in demand for hydrocarbons. At its height, the COVID- 19 pandemic had a significant negative effect on the global economy, supply chains and labor force participation, and created significant volatility in financial markets. Although the effects of the pandemic during 2022 were not as significant as prior years, new variants continued to cause waves of COVID- 19 cases around the world. The COVID- 19 pandemic and its ongoing variants may continue to have a material adverse effect on the demand for hydrocarbons and the prices at which they are sold, which may impact our revenues and operating income, our cash distributions and our business generally. It is impossible to predict the effect of the continued spread, or fear of continued spread, of COVID- 19 and its ongoing variants globally. No assurance can be given that public health threats will not have a material adverse effect, and that any further spread of COVID- 19 and its ongoing variants will not have a material adverse effect, on our business, operations and financial results. The Partnership may be adversely affected by the international economic instability caused by ongoing global conflicts. ~~During~~ **From** 2022 ~~and~~ **through** ~~2023~~ **2024** , multiple global military conflicts arose ~~,~~ causing instability in the international economy which may continue into ~~2024~~ **2025** . Although the length, impact and outcome of these military conflicts are highly unpredictable, an escalation or expansion of any of these conflicts could lead to significant market and other disruptions, including disruptions to the oil and gas industry, significant volatility in commodity prices and supply of energy resources, instability in financial markets, supply chain interruptions, political and social instability and other material and adverse effects on macroeconomic conditions. It is not possible at this time to predict or determine the ultimate consequences of these ongoing conflicts. We will continue to incur increased costs as a result of operating as a public company, and our management will continue to devote substantial time to compliance with our public company responsibilities and corporate governance practices. As a public company, we have incurred and will continue to incur significant legal, accounting and other expenses, particularly since we are now a large accelerated filer and are no longer a smaller reporting company. The Sarbanes-Oxley Act of 2002, or the Sarbanes Oxley Act, the Dodd- Frank Wall Street Reform and Consumer Protection Act, the listing requirements of the Nasdaq Global Select Market and other applicable securities rules and regulations impose various requirements on public companies. Our management and other personnel will need to continue to devote a substantial amount of time to comply with these requirements. Moreover, these rules and regulations have increased, and will continue to increase, our legal and financial compliance costs and will make some activities more time- consuming and costly. If, notwithstanding our efforts to comply with new or changing laws, regulations, and standards, we fail to comply, regulatory authorities may initiate legal proceedings against us, and our business may be harmed. Further, failure to comply with these laws, regulations and standards may make it more difficult and more expensive for us to obtain directors' and officers' liability insurance, which could make it more difficult for us to attract and retain qualified members to serve on our board of ~~directors~~ **managers** or committees or as members of senior management. These rules and regulations are often subject to varying interpretations, in many cases due to their lack of specificity, and, as a result, their application in practice may evolve over time as new guidance is provided by regulatory and governing bodies. This could result in future uncertainty regarding compliance matters and higher costs necessitated by ongoing revisions to disclosure and governance practices. Disclosure Regarding Forward- Looking Statements Statements included in this report that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), are forward- looking statements. These statements can be identified by the use of forward- looking terminology including" may,"" believe,"" will,"" expect,"" anticipate,"" estimate,"" continue," or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other forward- looking information. These forward- looking statements are made based upon management' s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and, therefore, involve a number of risks and uncertainties. We caution that forward- looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward- looking statements for a number of important reasons, including those discussed under" Risk Factors" and elsewhere in this report. Examples of such reasons include, but are not limited to, changes in the price or demand for oil and natural gas, public health crises including the worldwide coronavirus (COVID- 19) outbreak beginning in early 2020 and its ongoing variants, the conflict in Ukraine, the conflict between Israel and Hamas, changes in the operations on or development of our properties, changes in economic and industry conditions and changes in regulatory requirements (including changes in environmental requirements) and our financial position, business strategy and other plans and objectives for future operations.

You should read these statements carefully because they may discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other forward- looking information. Before you invest, you should be aware that the occurrence of any of the events herein described in" Item 1A – Risk Factors" and elsewhere in this report and in the Partnership’ s other filings with the Securities and Exchange Commission could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common units could decline, and you could lose all or part of your investment.